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STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chairman Robert A. Doyle John M. Espindola Robert M. Pickett Janis W. Wilson

In the Matter of the Consideration of the Revenue Requirement Designated as TA 334-4 Filed by ENSTAR NATURAL GAS COMPANY, A DIVISION OF SEMCO ENERGY, INC.	)))))	Docket No. U-22-081

PREFILED REPLY TESTIMONY
OF
DANIEL M. DIECKGRAEFF

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OF
DANIEL M. DIECKGRAEFF

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I. INTRODUCTION, PURPOSE, AND SUMMARY

Q. Are you the same Daniel M. Dieckgraeff who previously submitted Prefiled Direct Testimony in this docket?

A. Yes, I am. For the Commissioners' and the parties' convenience, the short-hand references, including acronyms used in this Prefiled Reply Testimony, have the same meaning as defined in my Prefiled Direct Testimony.

Q. What is the purpose of your Prefiled Reply Testimony?

A. The purpose of my testimony is to discuss certain topics raised by the intervenors in their filed responsive testimony. These topics cover, but are not limited to, format of the revenue requirement schedule, weather normalization, adjustments to revenue, pension expenses, excess accumulated deferred income taxes, capital structure, rate design issues, excess demand penalties, SCPPFT service, and ENSTAR/APC internal nomination procedures. Specifically, I will address certain topics raised by witnesses Fiona K. Yiu and Ralph C. Smith on behalf of the Office of the Attorney General, Regulatory Affairs and Public Advocacy Section ("RAPA"), Kimberly A. Henkel on behalf of Matanuska Electric Association, Inc. ("MEA") and Catherine E. Palazzari on behalf of Homer Electric Association, Inc. and Alaska Electric Energy Cooperative, Inc. (collectively "HEA").

II. REVENUE REQUIREMENT SCHEDULES FORMAT (RAPA Adjustment 1)

Q. Beginning at page 13 of her Prefiled Testimony, RAPA's Ms. Yiu recommends the removal of Gas Cost Adjustment costs and revenues from ENSTAR's revenue requirement for "an accurate presentation of ENSTAR's revenue requirement and rate proposal." How do you respond?

A. This recommendation is misplaced. ENSTAR's presentation of its revenue requirement complies with 3 AAC 48.275(a) and is consistent with its past revenue requirement presentations. I have been directly involved with every ENSTAR rate case except its first, as well as many additional ENSTAR 275(a) presentations to the Commission, and this is the first time I can recall a party raising this stylistic matter. Ms. Yiu's proposed adjustment (RAPA Adjustment 1) has no effect on the revenue requirement itself, just the presentation.

Q. Does ENSTAR's revenue requirement as filed in TA334-4 give an accurate presentation of ENSTAR's revenue requirement and rate proposal?

A. Yes. Ms. Yiu admits at page 13 of her testimony that ENSTAR "did include a calculation of [its] revenue requirement without the cost of gas." ENSTAR's revenue requirement without the cost of gas is found on page 4 of ENSTAR's 275(a) filing, Attachment B to TA334-4, and is updated on page 4 of Ms. Guintu' s Exhibit CNG-4. Ms. Yiu's proposed adjustment is unnecessary.

Q. What additional considerations should the Commission keep in mind when analyzing Ms. Yiu's proposed adjustment RAPA 1?

A. ENSTAR's format allows users to easily compare the revenue requirement to the amounts reported in its Annual Operation Report to the Commission, its annual Regulatory Cost Charge report to the Commission, and its general ledger. Finally, the Commission and its staff have indicated a strong preference to ENSTAR in the past to provide the impact of rate changes on the overall bill to customers, which includes gas cost. ENSTAR's presentation clearly shows that overall impact to customers, as well as the overall impact to the non-gas portion of the bill.

III. <u>WEATHER NORMALIZATION (ENSTAR Schedule O)</u>

Q. On page 20 of her Prefiled Responsive Testimony, MEA's Ms. Henkel states that MEA agrees with ENSTAR conducting a weather normalization adjustment for its 2021 Test Year. However, she claims that ENSTAR may have overcorrected its gas sales volumes. Do you agree with her analysis of this issue?

A. No. Her analysis, shown on Exhibit KAH-03, compares ENSTAR's pro forma adjustment to forecasts that ENSTAR prepares for other purposes, primarily for gas supply planning. The comparison is inapt. ENSTAR uses a different methodology when forecasting gas supply demand to avoid underestimating its gas supply requirements. Understandably, ENSTAR wishes to be accurate, yet conservative, in forecasting demand to ensure it has sufficient gas supplies to meet its customer's needs. Further, her comparison uses unreliable data. She uses a mixture of actual and estimated data for 2022 and customer counts for 10 months, not a full year.

As I stated on pages 15 and 16 my Prefiled Direct Testimony, the methodology ENSTAR used for its pro forma adjustment is a simplified calculation that has been accepted by the RCA in the past. I will also note that it is similar to the methodology that RAPA witnesses have proposed in the past.

Q. You state that the methodology used in ENSTAR's pro forma adjustment is similar to a methodology that RAPA has proposed in the past. Did RAPA disagree with ENSTAR's weather normalization pro forma adjustment in this docket?

A. No. RAPA witnesses did not comment on ENSTAR's weather normalization pro forma adjustment in their responsive testimony.

Q. On page 22 of her testimony, Ms. Henkel states that MEA believes ENSTAR needs to include a consistent pro forma adjustment for weather normalization in subsequent rate cases. Is her testimony in line with the Commission's precedent and guidance on weather normalization adjustments?

A. No, it is not. I discussed the Commission's guidance from page 94 of Order U-16-066(19) beginning at the bottom of page 14 of my Prefiled Direct Testimony. As they stated, weather normalization adjustments are only made when "the test year was a climatic anomaly where temperature departed significantly from the normal range of temperature fluctuations." Ms. Henkel's recommendation is not appropriate as it would call for adjustments in every case, not just when there was a significant departure from the normal range.

Q. HEA's Ms. Palazzari briefly mentions ENSTAR's weather normalization pro forma adjustment on page 52 of her testimony while discussing risk. Do you have a response to her comments?

A. It appears Ms. Palazzari confuses ENSTAR's weather normalization pro forma adjustment to its revenue requirement with a weather normalization adjustment clause ("WNA Clause") used by some utilities in other jurisdictions. With a WNA Clause, customer billings are adjusted each month to reflect differences from weather that has been found by a utility and a regulator to be a "normal year" (sometimes on a delayed basis).

Q. Is ENSTAR proposing a WNA Clause?

A. No, it is not. It is proposing a one-time weather normalization pro forma adjustment to its test year volumes and its revenue requirement because, as I discuss beginning at page 15 of my Prefiled Direct Testimony, "[t]he 2021 test year weather departed significantly from the normal range of temperature fluctuations[.]" Thus, Ms. Palazzari's risk comments are misplaced.

IV. ADJUSTMENTS TO TRANSPORTATION REVENUES

Q. Beginning at page 18 of her testimony, MEA's Ms. Henkel recommends revising ENSTAR's revenue requirement and rate design to reflect a change to MEA's Contracted Peak Demand that became effective October 1, 2022. Is her proposed adjustment appropriate?

A. No, it is not. The change in Contracted Peak Demand occurred after ENSTAR filed TA334-4, as Ms. Henkel admits on page 18 of her testimony. The Commission's precedent for the inclusion of a known and measurable adjustment is that the item has to be known and measurable at the time the utility files its rate case.[1] Accordingly, ENSTAR has not proposed any additional pro forma adjustments in its Prefiled Reply Testimony for costs that have become known and measurable since it filed TA334-4. The revised VLFT Service Agreement with MEA that increased Contracted Peak Demand was executed on September 16, 2022 (*see* Exhibit DMD-9), over a month and a half after ENSTAR filed its rate case and was not known and measurable at the time of ENSTAR's filing.

[1] E.g., in Order U-18-043(15) at 23 - 25, the Commission rejected CINGSA's pro forma adjustment, proposed in Reply Testimony, for changes in payroll rates that were known and measurable at the time Reply testimony was filed but not known and measurable at the time of its original revenue requirement filing.

Q. On page 19, Ms. Henkel also recommends revising ENSTAR's revenue requirement and rate design to reflect a special contract ENSTAR entered into with Golden Valley Electric Association, Inc. ("GVEA") that was filed in December 2022. Is her proposed adjustment appropriate?

A. No. As with the change in the MEA Contracted Peak Demand I discussed above, this special contract, which was not approved by the Commission until January 20, 2023,[2] was entered into and approved after ENSTAR's rate case was filed. It does not meet the Commission's precedent for inclusion because it was not known and measurable at the time of filing. Further, the special contract expires after two years, and it has no provision for renewal. It explicitly states that ENSTAR does not have an obligation to serve GVEA nor does it have any obligation to provide Gas Sales Service to GVEA after the term of this agreement. It would be inappropriate to adjust ENSTAR's permanent rates for a service that is only contracted for a very limited time. Finally, the GVEA volumes under the special contract are not incremental. They simply replace some of the gas volumes that were used to generate power for GVEA under its 2019 Memorandum of Understanding with Chugach.[3] The special contract volumes replace volumes transported on ENSTAR's system in the 2021 Test Year that were used to generate economy energy sales to GVEA.

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[2] *See* Letter Order # L2300017 dated January 20, 2023, attached as Exhibit DMD-10, and TA337-4. GVEA also submitted the agreement for approval in TA359-13.

[3] Exhibit DMD-11 TA359-13 Supplemental, dated December 2, 2022.

V. PENSION EXPENSES (ENSTAR Schedule M)

Q. Beginning at page 25 of her testimony, Ms. Yiu proposes an adjustment to ENSTAR's Pension Expenses pro forma adjustment. Please discuss her proposal.

A. Ms. Yiu, beginning at page 25 of her testimony, acknowledges that ENSTAR's pension expenses have fluctuated significantly in the past five years and meet the "clearly anomalous" standard articulated by the Commission for the use of an average of past years' expenses. ENSTAR followed Commission precedent when it computed its Pension Expenses pro forma adjustment by using data for the historical test year and the four preceding years (i.e., 2017-2021).[4] Ms. Yiu, however, ignored the Commission's precedent of the test year and the years preceding it to calculate an average for the pro forma adjustment. Instead, she included an amount for 2022, the year after the test year and dropped 2017. I will further note that ENSTAR filed this case on August 1, 2022, well before the conclusion of 2022. Ms. Yiu's proposed adjustment should be rejected as inconsistent with Commission precedent.

VI. EXCESS ACCUMULATED DEFERRED INCOME TAXES

Q. On page 21 of your Prefiled Direct Testimony, you discussed a review of ENSTAR's protected/unprotected excess ADIT components to comply with recently-issued IRS private letter rulings concerning costs of plant removal. Has that review been completed?

A. Yes. ENSTAR retained Price Waterhouse Coopers ("PWC") to conduct the review, which was completed in May 2023. In addition to reviewing the treatment for cost of

[4] In Order U-19-070(21)/U-19-071(21)/U-19-087(18)/U-19-088(18), dated January 19, 2021, at pages 22-24 the Commission approved the use of a five-year average that included the test year and the previous four years. An extract of the relevant pages of the Order is attached as Exhibit DMD-12.

plant removal, the review was expanded to include the effect of the equity allowance for funds used during construction. The PWC report is attached as Exhibit DMD-13. ENSTAR provided the report and related workpapers to the parties to this proceeding as supplemental discovery in May 2023.

Q. Did ENSTAR make any adjustments to excess ADIT based on the PWC review?

A. Yes. Based on the review, ENSTAR has increased protected excess ADIT by a net of $4,023,277 and increased negative unprotected excess ADIT by a net of $4,023,277. These adjustments take into account the effect of the removal costs on book depreciation rates and the effect of the equity allowance for funds used during construction in the cost of plant. In reviewing the excess ADIT data, ENSTAR also found that it had inadvertently missed a negative $2,782 unprotected excess ADIT item in its original 275(a) filing. This item is properly included in the updated excess ADIT summary.

Q. Has ENSTAR revised its revenue requirement to reflect the results of the PWC review and the inadvertently missed unprotected excess ADIT item?

A. Yes. ENSTAR has updated the calculation of its revenue requirement for the updated excess ADIT amount, as well as other issues which are identified in Ms. Guintu's Prefiled Reply Testimony. As I have noted earlier, the updated revenue requirement is included as Exhibit CNG-4 to Ms. Guintu's Prefiled Reply Testimony.

VII. CAPITAL STRUCTURE

Q. HEA's Ms. Palazzari recommends using AltaGas' capital structure at December 31, 2021, instead of ENSTAR's. Do you have any comments about her recommendation?

A. ENSTAR witness Dylan D'Ascendis will address this issue in his Prefiled Reply Testimony. However, I would like to point out that Ms. Palazzari's proposal is inconsistent with RCA precedent and its treatment of ENSTAR in the past, including in ENSTAR's most recently adjudicated rate case, Docket U-16-066. It has been my experience that the Commission uses a utility's capital structure (even when its parent company has a different capital structure), except in very unusual and rare cases. Those being where the equity percentage is significantly low (generally below 35%) or significantly high (70% or above), or where the utility has requested a deviation from actual for good cause (as determined by the Commission). Since 2000, I am only aware of four instances out of the eleven adjudicated revenue requirements of investor-own utilities where the Commission has used something other than the utilities' own actual capital structure. In three of those dockets (as set out in Orders U-00-088(12), U-03-082(6) and U-09-090(8)), the Commission accepted the hypothetical capital structure proposed by the Utility. In Order U-00-115(13)/U-00-116(12)/U-00-146(10), the Commission adopted a hypothetical capital structure that was very close to the Utility's actual capital structure. ENSTAR's situation in this case is not like any one of those very unusual and rare cases where the actual capital structure was not used. As the Commission noted in Order U-18-043(15), "[i]f known and appropriate, we typically approve a public utility's actual capital structure and actual cost of debt."[5]

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[5] Order U-18-043(15), *Order Resolving Revenue Requirement and Cost-of-Service Issues and Requiring Filings*, dated August 16, 2019, at 62 citing Order U-16-094(9)/U-17-008(13), *Order Resolving all Revenue Requirement and Cost-of-Service Issues, Approving Depreciation Rates, Approving Revised Cost of Power Adjustment, Requiring Filings, and Allowing Parties to File Comment*, dated March 23, 2018.

VIII. <u>RATE DESIGN ISSUES</u>

Q. Beginning on page 6 of her Prefiled Testimony, Ms. Henkel discusses MEA's opposition to ENSTAR's proposed straight fixed variable rate design for the large transportation customers "at this time." What is her main reasoning for waiting?

A. On her page 7, Ms. Henkel cites to filings made in January 2023 in compliance with Order I-15-001(15) by the Railbelt electric utilities with their 10-year annual gas requirements, stating the filings demonstrate that there is no known or measurable reduction in transportation customers' volumes projected for the next ten-year period. Her assessment of no decline differs with Power Generation Demand Planning Assumptions shown on Figure 4 of the *Alaska Utilities Working Group Phase I Assessment: Cook Inlet Gas Supply Project* dated June 28, 2023, where MEA is a member of the working group.[6] The figure clearly shows that the power generation gas requirements demand assumption (normal) begins to decline from the current 2023 level starting in the 2026-2027 timeframe.

Q. Do you have any other observations on Ms. Henkel's testimony concerning power plant usage on ENSTAR's system?

A. Yes. The ongoing level of power plant usage of ENSTAR's system has been an issue in every one of ENSTAR's rate cases in the last three decades, going back to Docket U-00-088. When power plant usage of ENSTAR's system decreases from the level used to set rates, ENSTAR does not collect the class revenue requirement that was used to set rates. ENSTAR witness Inna Johansen's Prefiled Direct Testimony contains a

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[6] Attached as Exhibit DMD-14. The entire report was provided to the RCA on June 28, 2023, following its Public Meeting where the results of the Phase I were presented. The full report is also available on ENSTAR's website at: www.enstarnaturalgas.com

table on page 17 that graphically depicts the year-after-year reduction in transport volumes on ENSTAR's system, 2018 through the test year, from the volumes used to set rates in Docket U-16-066. The VLFT volumes in the 2021 test year are 11% below those used to set rates, while the volumes in 2020 were 12% below.

Q. If the VLFT volumes were to remain at the same level as the 2021 Test Year going forward, would the rate design proposed by ENSTAR in this proceeding result in collection of the same amount in rates from the VLFT rate class as compared to ENSTAR's current rate design?

A. Yes. If volumes remained the same, both rate designs would collect the same total revenue.

Q. From a high level, if volumes increased, what would be the effect on revenue when comparing the two rate designs?

A. If VLFT volumes increased, ENSTAR's current rate design would collect more revenue from the VLFT rate class than the SFV rate design would.

IX. EXCESS DEMAND PENALTIES

Q. In pages 14-18 of her testimony, MEA's Ms. Henkel expresses concerns and takes issues with ENSTAR's excess demand penalty provision which is currently in the VLFT rate schedule and is also in the proposed SCPPFT rate schedule. How do you respond?

A. MEA raised most of these same issues in ENSTAR's last rate case, Docket U-16-066. There has been no substantive change in the VLFT excess demand penalty provision since Docket U-16-066 was decided. In Order U-16-066(19) at page 119 the Commission stated: "We find that the excess demand penalty associated with the

VLFT rate schedule is reasonable and no revision is necessary." There is no reason to make any changes to the provision at this time.

Q. At page 17 and again at page 19, Ms. Henkel states that ENSTAR specifically waives any potential excess demand penalties for volumes associated with ENSTAR's special contract with GVEA and implies that this results in unequal treatment of customers in similar positions. How do you respond?

A. While Ms. Henkel does not cite a specific provision in the GVEA special contract (attached as Exhibit DMD-10), it appears she is referring to the last paragraph of Section 3.b.(1) on page 4 of the special contract that states:

> In the event that the Generation Entity exceeds its Contract Peak Demand on a Day under its TSA due to receipt of Gas under this Agreement, the Company will waive the Excess Demand penalty for volumes delivered on the Customer's behalf to the Generation Entity that Day under this Special Contract.

The purpose of this provision is to give the Generation Entity for GVEA credit for the Daily Contract Quantity (Contracted Peak Demand) that GVEA is paying for so that the Generation Entity is not assessed an excess demand penalty under either the VLFT or the SCPPFT rate schedules. It is similar to Section 2160a(2) of the proposed SCPPFT rate schedule and waiver for Economy Energy Sales that is present in both the VLFT (Tariff Section 2150c(3)) and SCPPFT (Tariff Section 2160c(4)) rate schedules. Ms. Henkel's criticism is misplaced.

X. <u>SCPPFT SERVICE</u>

Q. Beginning at page 14 of her testimony, Ms. Henkel recommends a modification to ENSTAR's proposed SCPPFT at Tariff Section 2160a(2). Is her modification necessary?

A. No. Ms. Henkel's testimony indicates that she is concerned that gas shipped under the SCPPFT could trigger a violation of the Daily Balancing Tolerances under Tariff Section 1605e(3) of ENSTAR's tariff. The provision provides for the matching of "Required Receipts" to actual gas deliveries to ensure that transportation customers have sufficient gas coming into ENSTAR's system to match what is being delivered to them. Required Receipts are defined at Tariff Section 1605e(2)(a) as the amount of gas received into ENSTAR's system that the transportation customer actually has delivered at its Delivery Points. For example, the gas MEA is taking off of ENSTAR's system at its power plant is MEA's Required Receipts.

The requirement for a transportation customer to match the gas entering ENSTAR's system on its behalf to that delivered to its power plant doesn't change under the SCPPFT rate schedule. Each SCPPFT Customer still will need to make sure that enough gas is received into the ENSTAR system on that Customer's behalf to match what is being delivered into its power plant. If a SCPPFT Customer is having gas received into ENSTAR's system for use at another SCPPFT Customer's power plant, that gas should be identified to ENSTAR as being provided on behalf of the generating SCPPFT Customer.

XI. ENSTAR AND APC NOMINATION PROCEDURES

Q. At pages 24 - 26 of her testimony, Ms. Henkel states that MEA continues to have a concern regarding the relationship between ENSTAR and Alaska Pipeline Company ("APC" or "APLC") and recommends that ENSTAR should be required to follow the same nomination and revision procedures and be subject to the same penalties as other shippers. Is this the proper proceeding to address this issue?

A. No. The Commission rejected similar assertions from the intervenors in Docket U-16-066. In Order U-16-066(19) at page 123 the Commission stated:

> During the course of this proceeding, various intervenors presented testimony and/or argument asserting that ENSTAR and APLC should be regulated as separate entities. However, the scope of this proceeding is determined by the tariff revisions filed by ENSTAR, and a collateral issue such as regulatory structure becomes relevant only to the extent necessary to determine whether the revised rates are lawful. We have determined the basis for just and reasonable rates without reaching this issue. Therefore, this argument is not appropriately addressed in the context of this docket.

The relationship between ENSTAR and APLC, as raised by MEA, is not a revenue requirement, cost-of-service, or rate design matter, it is a collateral matter and it is not appropriate to address in this proceeding. The Commission regulates ENSTAR and APLC as a single entity with a single tariff. As noted by the Commission on page 30 of Order U-22-032(6)/U-22-033(6) dated December 21, 2022:

> Despite holding two separate certificates, ENSTAR/APLC are jointly regulated for ratemaking purposes and have been since 1975.

Order U-22-081(6) in this Docket, dated April 13, 2023, at page 8 states:

> [I]n previous dockets the Commission has allowed ENSTAR and APLC to have a combined rate case and allowed for APLC to use ENSTAR's tariff. The Commission accepted and allowed ENSTAR to use a combined revenue requirement in TA334-4 and it will analyze it only as a combined revenue requirement.

Q. While it is not the appropriate matter for this proceeding, do you have a comment about Ms. Henkel's recommendation about ENSTAR and APLC intercompany nomination and revision procedures, and penalty provisions?

A. In my time at ENSTAR, I have reviewed a very large number of local gas distribution company ("LDC") tariffs. Most provide natural gas sales service to general service type customers as well as transportation service to large customers, which can include industrial and power plant customers. I do not recall ever seeing an LDC tariff that includes the type of provisions she is recommending here.

XII. CONCLUSION

Q. Does this conclude your Prefiled Reply Testimony?

A. Yes.

STATE OF ALASKA
DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT

Mike Dunleavy, Governor
Julie Sande, Commissioner
Keith Kurber II, Chairman

Regulatory Commission of Alaska

September 19, 2022

In reply refer to: Tariff Section
File: TA335-4

Chelsea Guintu
Supervisor of Rates and Regulatory Affairs
ENSTAR Natural Gas Company
P.O. Box 190288
Anchorage, AK 99519-0288

Dear Ms. Guintu:

On September 16, 2022, ENSTAR Natural Gas Company (ENSTAR) filed TA335-4, providing a copy of its Firm Transportation Service Agreement with Matanuska Electric Association, Inc. (MEA), executed September 16, 2022. ENSTAR is required by Order No. U-06-012(2) to file all new transportation service agreements as informational filings within ten days of execution.

Enclosed is a validated copy of the Firm Transportation Service Agreement with MEA, filed September 16, 2022, by ENSTAR with TA335-4. Please note that the validation stamp reads "Informational Filing Only". In addition, a reference to TA335-4 has been added to the bottom left corner of each page of the agreement.

Sincerely,

REGULATORY COMMISSION OF ALASKA

Becki Alvey
Becki Alvey (Sep 19, 2022 10:06 AKDT)

Becki Alvey
Tariff Section Manager

Enclosure

701 West 8th Avenue, Suite 300, Anchorage, Alaska 99501-3469
Telephone: (907) 276-6222 Fax: (907) 276-0160 TTY/Alaska Relay: 7-1-1 or (800) 770-8973
Website: http://rca.alaska.gov

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MATANUSKA ELECTRIC ASSOCIATION, INC.
FIRM TRANSPORTATION SERVICE AGREEMENT
September 2022

This Service Agreement is made between **Matanuska Electric Association, Inc.** (the "Customer) and **ENSTAR Natural Gas Company**, a division of SEMCO Energy, Inc., (the "Company) on **September 16, 2022** for natural gas transportation service to be supplied under the Company's Rate Schedule Very Large Firm Transportation Service (VLFT), which is incorporated by reference.

1. The general terms and conditions for this service are set out in the Company's tariff, including Sections 1605 and 1640. The rates for this transportation service are set out in the Company's tariff Section 2150. The monthly rate and customer charge and demand charge applies to each individual Delivery Point receiving service under Schedule VLFT, in accordance with tariff Section 704. Volumes from individual Delivery Points will not be combined or aggregated unless it is for the convenience of the Company.

2. VLFT Service to the Customer will commence **on October 1, 2022** and the Service Agreement shall remain in effect through October 31, 2023, and Year to Year thereafter until canceled upon six Months' notice by either party. Final notice of the commencement date for Service will be documented by e-mail or fax. The gas to be transported is for the ultimate delivery only to the end user(s) listed as Delivery Points in Attachment B.

3. The Customer agrees to a **Contracted Peak Demand of <u>24,500</u> Mcf per day**, and agrees to pay the Company a Demand Charge, as calculated under Schedule VLFT, in accordance with the Company's tariff Sections 2150b and 2150c. If this Service Agreement is extended by the parties, the Customer will pay a Demand Charge for the period that it is extended. If, as the result of the Service commencement date or Service termination date, Service is provided for a partial Month, the Demand Charge and Customer Charge will be pro-rated based upon the ratio of the number of days Service was provided during the Month over the number of Days in the Month.

4. If the Company is unable to deliver the Contracted Peak Demand on any Day due to capacity limitations of its pipeline system, the Demand Charge for that Month will be reduced to reflect the amount that was actually delivered for that Day taking into account the number of Days during the Month that capacity was not limited.

5. Receipt Points for gas transported are listed in Attachment A along with the gas suppliers and a contact for each receipt point. The Delivery Point(s) are listed in Attachment B along with a contact for each Delivery Point.-The Customer agrees to use reasonable effort to notify the Company's gas control dispatcher of actual production plans and any material change by phone at (907) 334-7788, by facsimile at (907) 334-7779, or by e-mail at enstar.gascontrol@enstarnaturalgas.com.

6. The Customer agrees to the terms and conditions of payment provided in the Company's tariff.

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7. Notices to the Customer and Company, and billings for service to the Customer shall be mailed or delivered to the addresses listed below. Telephone and facsimile numbers are provided for other communications.

Notices to Customer:

For scheduling and Day to Day Operations:
Matanuska Electric Association, Inc.
ATTN: Energy Supply
Address
Physical: 28705 Denaina Elders Rd
Chugiak, AK 99567
Mailing: P.O. Box 2929
Palmer, AK 99645
Telephone: (907) 761-9523
Facsimile:
E-Mail: fuel@mea.coop

For Payments:
ATTN: Accounts Payable
Address
Physical: 163 E. Industrial Way
Palmer, AK 99645
Mailing: P.O. Box 2929
Palmer, AK 99645
Telephone: (907) 761-9239
Facsimile: (907) 761-9324
E-Mail: AccountsPayable@mea.coop

Notices to Company:

ENSTAR Natural Gas Company
ATTN: Gas Control
Address
Physical: 401 E. International Airport Rd
Anchorage, AK 99518
Mailing: P.O. Box 190288
Anchorage, AK 99519
Telephone: (907) 334-7788
Facsimile: (907) 334-7779
E-Mail:
enstar.gascontrol@enstarnaturalgas.com

ATTN: Gas Accounting Manager
Address
Physical: 3000 Spenard Road
Anchorage, AK 99503
Mailing: P.O. Box 190288
Anchorage, AK 99519
Telephone: (907) 334-7660
Facsimile: (907) 334-3403
E-Mail:
denise.romans@enstarnaturalgas.com

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For all other Notices:

ATTN: Energy Supply Manager
Address
Physical: 28705 Denaina Elders Rd
Chugiak, AK 99567
Mailing: P.O. Box 2929
Palmer, AK 99645
Telephone: (907) 761-9360(w)
(907) 707-3320 (m)
Facsimile: (907) 689-9360
E-Mail: kim.henkel@mea.coop

ATTN: Director, Gas Supply Operations
Address
Physical: 401 E. International Airport Rd
Anchorage, AK 99518
Mailing: P.O. Box 190288
Anchorage, AK 99519

Telephone: (907) 334-7830
Facsimile: (907) 334-7671
E-Mail:
inna.johansen@enstarnaturalgas.com

Matanuska Electric Association, Inc.

By: Tony Zellers

(Printed:) Tony Zellers

Title: Sr. Director of Power Supply

Date: 9/16/2022

ENSTAR Natural Gas Company

By: I. Johansen

(Printed:) Inna Johansen

Title: Director of Gas Supply Operations

Date: 9/16/2022

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ATTACHMENT A
RECEIPT POINTS

West Side Cook Inlet /Beluga-Anchorage Pipeline

1. **Beluga Unit Area Connection (ENSTAR/APC Station B601, Meters 170 A & B)**
   At the upstream flange of Alaska Pipeline Company's meter at or near the inlet of Alaska Pipeline Company's Beluga-Anchorage pipeline located within the West 1/2, Southwest 1/4, of Section 26, Township 13 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

2. **APC-KBPL Interconnection Point, APC Terminus Interconnect (at Beluga Point) (ENSTAR/APC Station B605, Meters 700 & 701, BLPC Nos. 8101 & 8102)**
   At the upstream flange of Alaska Pipeline Company's meter at or near the connection of Alaska Pipeline Company's Beluga-Anchorage pipeline and Kenai Beluga Pipeline's Granite Point-Beluga pipeline located within the West 1/2 of the Southwest 1/4 of Section 26, Township 13 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

3. **APC West Side Pool**

   a. **Pretty Creek Unit Connection (ENSTAR/APC Station B602, Meters 189 A & B)**
   At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the Pretty Creek Unit and Alaska Pipeline Company's Beluga-Anchorage pipeline located in the South 1/2 of Section 28 Township 14 North, Range 9 West, Matanuska-Susitna Borough, Seward Meridian, State of Alaska.

   b. **Lewis River Unit Connection (ENSTAR/APC Station B603, Meters 168 A &B)**
   At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the Lewis River Unit and Alaska Pipeline Company's Beluga-Anchorage pipeline located in the Northwest 1/4 of Section 2, Township 14 North, Range 9 West, Matanuska-Susitna Borough, Seward Meridian, State of Alaska.

   c. Stump Lake/Ivan River Connection (ENSTAR/APC Station B604, Meters 600 & 601)
   At the upstream flange of Alaska Pipeline Company's meter located at or near the connection of the pipeline from the Stump Lake and Ivan River units and Alaska Pipeline Company's Beluga-Anchorage pipeline the Southeast 1/4 of the Northwest 1/4 of the Northeast 1/4 of the Southwest 1/4 of Section 22, Township 14 North, Range 9 West, Seward Meridian, State of Alaska

(Volumes from the above three meters may be nominated and accounted for as an aggregate volume, if mutually agreed upon by both Parties. APC West Side Pool.)

The parties agree that all Receipt Points listed below will be used for emergency and Company operational purposes only. The Company must agree to each specific use of these delivery points:

East Side Cook Inlet

1. **APC East Side Pool**

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a. **Kenai Unit Area Connection (ENSTAR/APC Station K670, Meters 500 & 502)**
At the upstream flange of the Alaska Pipeline Company's master meter located at or near the inlet of the Alaska Pipeline Company's Kenai-Anchorage pipeline in Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

b. **West Fork Connection (ENSTAR/APC Station K676, Meters 924 & 925, Meter 2200)**
At the upstream flange of Alaska Pipeline Company's meter at or near the connection of the pipeline from the West Fork field and Alaska Pipeline Company's Kenai-Anchorage pipeline located in the South 60 feet of the Northwest 1/4 of the Northwest 1/4 of Section 12, Township 5 North, Range 9 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

c. **Beaver Creek Unit Area Connection ((ENSTAR/APC Station K671, Meter 1100 A)**
At the upstream flange of the Alaska Pipeline Company's meter at or near the connection of the pipeline from the Beaver Creek Unit and Alaska Pipeline Company's Royalty Pipeline located in the Northwest 1/4 of the Southwest 1/4 of Section 7, Township 6 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

d. **Sterling Unit Connection (ENSTAR/APC Station K677, Meter 9100)**
At the upstream flange of the Alaska Pipeline Company's meter at or near the connection of the pipeline from the Sterling Unit and Alaska Pipeline Company's Royalty Pipeline located within the Northeast 1/4 of Section 9, Township 5 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

e. **North Kenai Lateral – ENSTAR Station K276 (Hilcorp Meter 520)**
At the upstream flange of Hilcorp's meter located at or near the inlet of the Company's North Kenai Lateral pipeline in Government Lot 1, Section 21, Township 7 North, Range 12 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

(Volumes from the above five meters may be nominated and accounted for as an aggregate volume, if mutually agreed upon by both Parties. APC East Side Pool.)

2. **APC-KBPL Southern Interconnection Point (ENSTAR/APC Station K681, Meter 411)**
At the downstream flange of the meter at Alaska Pipeline Company's (APC') metering point located at the Southern terminus of the Kenai Beluga Pipeline's Kenai Nikiski pipeline and the lateral to the inlet of APC's Kenai to Anchorage Pipeline) in Southeast ¼ of Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

3. **APC-KBPL Interconnection Point/KKPL Terminus into APC (ENSTAR/APC Station K670, Meter 601)**
At the downstream weld of the 8-inch electronic isolation fitting located just outside of Kenai Beluga Pipeline's meter building located at the northern terminus of Kenai Beluga Pipeline's Kenai to Kachemak pipeline and Alaska Pipeline Company's (APC's) lateral to the inlet of APC's Kenai-Anchorage pipeline in Southeast ¼ of Section 30, Township 5 North, Range 11 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

Supplier for all Receipt Points:

Hilcorp Alaska, LLC:	Hilcorp Alaska Gas Control	(907) 283-2552
	Hilcorp Gas Scheduling Group	(907) 777-8446
	Emergency Number	(907) 398-8584

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Additional Suppliers for specific Receipt Points:

Beluga Unit Area Connection (ENSTAR/APC Station B601, Meters 170 A & B)

CEA:	Director, System Control	(907) 762-4779

Beluga Pipeline Company Connection (ENSTAR/APC Station B605, Meters 700 & 701, BLPC Nos. 8101 & 8102)

CEA:	Director, System Control	(907) 762-4779
Furie:	Mark Slaughter	(907) 277-3726 (w) (907) 632-2474 (m)

ATTACHMENT B
DELIVERY POINTS

Eklutna Generation Station (ENSTAR/APC Station B256)

At the downstream flange of the Company's meter at or near the outlet of the Company's lateral pipeline located within Tract 1, MEA Eklutna Generation Site Subdivision situated within the Northwest ¼ of the Southeast ¼ of Section 19, Township 16 North, Range 1 East, Seward Meridian, Anchorage Recording District, Third Judicial District, State of Alaska.

Contact: EGS Plant Manager
(907) 761-9344
josh.crowell@mea.coop

STATE OF ALASKA
DEPARTMENT OF
COMMERCE
COMMUNITY AND
ECONOMIC DEVELOPMENT

Mike Dunleavy, Governor
Julie Sande, Commissioner
Keith Kurber II, Chairman

Regulatory Commission of Alaska

January 20, 2023

In reply refer to: Tariff Section
File: TA337-4
LO#: L2300017

Chelsea Guintu
Supervisor of Rates and Regulatory Affairs
ENSTAR Natural Gas Company
P.O. Box 190288
Anchorage, AK 99519-0288

Dear Ms. Guintu:

On December 9, 2022, ENSTAR Natural Gas Company (ENSTAR) filed TA337-4 seeking approval of a Special Contract and Service Agreement for Gas Sales Service (Special Contract) between ENSTAR and Golden Valley Electric Association, Inc. (GVEA). On January 19, 2023, the Regulatory Commission of Alaska approved Tariff Sheet No. 190, filed December 9, 2022, and the Special Contract between ENSTAR and GVEA, filed January 13, 2023, by ENSTAR in TA337-4. The effective date of the tariff sheet and the special contract is January 23, 2023.

Enclosed are validated copies of the approved tariff sheet and Special Contract. Please note the effective date has been added to the bottom right corner of the tariff sheet and each page of the special contract. In addition, a reference to TA337-4 has been added to the bottom left corner of each page of the Special Contract.

BY DIRECTION OF THE COMMISSION (Commissioner Janis W. Wilson not concurring)

Sincerely,

REGULATORY COMMISSION OF ALASKA

Keith Kurber II
Keith Kurber II (Jan 20, 2023 14:41 AKST)
Keith Kurber II
Chairman

Enclosures

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Section 1900 - Schedule of Special Contracts

Customer	Contracted Service	Contract Effective Date	
Hilcorp Alaska, LLC	Contribution in Aid of Construction Agreement	August 16, 2012	
Chugach Electric Association	Transportation Service	December 15, 2013	
Alaska Electric and Energy Cooperative	Transportation Service	January 1, 2014	
Golden Valley Electric Association, Inc.	Gas Sales Service	November 30, 2022	N N

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SPECIAL CONTRACT AND SERVICE AGREEMENT WITH GOLDEN VALLEY ELECTRIC ASSOCIATION, INC. FOR GAS SALES SERVICE

This Special Contract and Service Agreement for Gas Sales Service ("Special Contract" or "Agreement"), dated November 30, 2022, is between ENSTAR Natural Gas Company, a division of SEMCO Energy Inc. ("Company"), and Golden Valley Electric Association, Inc. ("Customer"). The Company and the Customer may be referred to, collectively, as "Parties" and each, individually, as a "Party." Terms which are capitalized in this Special Contract are defined either in the Company's Tariff or in this Special Contract.

RECITALS

A. The Customer is a public utility with a Certificate of Public Convenience and Necessity to provide electric utility service to those communities from Cantwell to Delta Junction, as listed in its Current Operating Tariff on file with the Regulatory Commission of Alaska ("Commission" or "RCA"), as may be amended from time to time.

B. The Company is a public utility with a Certificate of Public Convenience and Necessity to provide natural gas utility service in and around Anchorage, Eagle River, Girdwood, Homer, Kenai, Palmer, Soldotna, and Wasilla ("Southcentral Alaska").

C. The Customer is not located within the Company's service territory.

D. The Company does not have a duty to serve the Customer.

E. The Customer has no natural gas-fired generation units in its service territory and seeks to acquire electricity generated in Southcentral Alaska utilizing the Company's Gas for the generation of electricity to be transmitted to the Customer's service territory.

F. The Company has secured access to an amount of natural gas supply in excess of the immediate needs of its Gas Sales customers to provide Gas Sales Service to the Customer as set out below.

G. The Company expressly disclaims any obligation to provide Gas Sales Service beyond the term of this Agreement.

H. The Customer has entered, or will enter, into one or more generation agreement(s) with an entity/entities (the "Generation Entity/ies") connected to the Company's Gas system (each a "Generation Agreement") for the generation of electricity to be transmitted to the Customer's service territory.

I. The Parties adopt the terms and conditions set forth herein to govern this transaction.

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AGREEMENT

1. PRINCIPLES OF CONSTRUCTION; ATTACHMENTS.

a. Principles of Construction. In this Agreement, unless the context otherwise requires:

(A) This Agreement is the entire agreement between the Parties respecting the subject matter thereof.

(B) Headings and the rendering of text in bold and/or italics are for convenience only and do not affect the interpretation of this Agreement.

(C) Words importing the singular include the plural and vice versa and the masculine, feminine and neuter genders include all genders.

(D) The words "hereof", "herein", "hereunder," and words of similar import shall refer to this Agreement as a whole and not to any particular provision of this Agreement.

(E) A reference to a Section, paragraph, clause, Party, or Attachment is a reference to that Section, paragraph, or clause of, or that Party or Attachment to, this Agreement unless otherwise specified.

(F) A reference to this Agreement shall mean this Agreement including any amendment or supplement to, or replacement, novation, or modification of this Agreement, but disregarding any amendment, supplement, replacement, novation, or modification made in breach of this Agreement.

(G) A reference to a person includes that person's successors and permitted assigns.

(H) The term "including" means "including without limitation" and any list of examples following such term shall in no way restrict or limit the generality of the word or provision in respect of which such examples are provided.

(I) References to any statute, code, or statutory provision are to be construed as a reference to the same as it may have been, or may from time to time be, amended, modified or reenacted, and include references to all bylaws, instruments, orders and regulations for the time being made thereunder or deriving validity therefrom.

(J) Each Party acknowledges and agrees that it has participated in the drafting of this Agreement and has had the opportunity to consult with legal counsel and any other advisors of its choice to its satisfaction regarding the terms and provisions of this Agreement and the results thereof. As a result, the rule of construction that an

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agreement be construed against the drafter will not be asserted or applied to this Agreement.

(K) All accounting terms not specifically defined herein shall be construed in accordance with U.S. generally accepted accounting principles.

(L) In the event of a conflict, a mathematical formula describing a concept or defining a term shall prevail over words describing a concept or defining a term.

(M) References to any amount of money shall mean a reference to the amount in US Dollars.

(N) The expression "and/or" when used as a conjunction shall connote "any or all of."

(O) Words, phrases or expressions which are not defined herein and which have a generally accepted meaning in the industry which is the subject of this Agreement shall have that meaning in this Agreement or in the Company's Tariff, as applicable.

(P) A waiver by either Party of any breach of the covenants and conditions to be performed under this Agreement by the other Party shall not be construed as a waiver of any succeeding breach of the same or any other covenant or condition.

(Q) Except as otherwise expressly provided in this Agreement, no amendments to or modifications of this Agreement shall be valid unless they are in writing and signed by the Parties.

b. Attachments. All of the Attachments that are attached to the body of this Agreement are an integral part of this Agreement and are incorporated by reference into this Agreement, including Attachment A – Delivery Point(s) and Attachment B – Generation Entity (Entities).

2. TERM

Effective Date; Contract Years 1 and 2. For the purposes of this Special Contract, the "Effective Date" shall mean the third Business Day following the later of: (i) RCA Approvals; and/or, (ii) the effective date of the [first] Generation Agreement(s) entered into by the Customer with the Generating Entities. For clarity, both (i) and (ii) must have occurred prior to the Effective Date. The term of this Special Contract shall be for two (2) Years (24 consecutive months) with each Year (12 months) deemed a "Contract Year" following the Effective Date (the "Term").

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3. GAS SALES SERVICE

a. **Gas Sales Service Volumes.** The Company agrees to provide Gas Sales Service to the Customer for the volumes set out below pursuant to the Company's tariff as specifically modified herein:

(1) The Annual Contract Quantity for Year 1 and 2 is 1,000,000 Mcf (1 Bcf).

(2) The Annual Contract Quantity will be delivered as the Daily Contract Quantity ("DCQ") on each day during the term as provided in the following chart:

Daily Contract Quantity	
Months	**DCQ (Mcf/d)**
October -March	3,600
April-September	1,900

b. **Delivery of Gas.** The Company shall deliver the Gas provided as Gas Sales Service to the Customer at the Delivery Point(s) listed in **Attachment A**.

(1) Delivery of Gas beyond the Delivery Point

Attachment B lists the entities that have entered into an agreement with the Customer to generate power for the Customer ("Generation Entities") utilizing the Gas provided under this Special Contract. The Customer will transfer the Gas provided to it under this Special Contract to the respective Generation Entity and that Generation Entity will utilize its currently-effective Firm Transportation Service Agreement ("TSA") with the Company to move the Gas from the Delivery Point(s) to the Generation Entity's generation facilities.

In the event that the Generation Entity exceeds its Contract Peak Demand on a Day under its TSA due to receipt of Gas under this Agreement, the Company will waive the Excess Demand penalty for volumes delivered on the Customer's behalf to the Generation Entity that Day under this Special Contract.

(2) Delivery of Gas at Continuous Rate and on Firm Basis

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The Company shall provide the Gas and the Customer shall receive the Gas under this Special Contract at a Continuous Rate. "Continuous Rate" means a rate of Gas delivery calculated by dividing the volume delivered per Day by 24 hours. The Company intends to deliver Gas at volumes that are not more than ten percent (10%) above or below the applicable DCQ over the course of one Day, unless otherwise excused pursuant to the terms and conditions of this Special Contract.

Each Day during the Term, except as otherwise provided in this Agreement, the Company will deliver, and Customer will receive, the applicable DCQ on a Firm basis. For the purposes of this Agreement, "Firm" means that a Party may interrupt its performance without liability only to the extent that such interruption is excused or permitted by the terms of this Agreement.

(3) Coordination and Communication

The Customer and the Company will communicate and work in good faith to coordinate (i) Gas deliveries with any applicable third parties, including the applicable Generation Entity/(Entities) and (ii) Gas deliveries during any anticipated shut-downs or curtailments, facility outages, maintenance, and other scheduled or irregular events.

(4) Rescheduling of Deliveries

By mutual agreement of the Parties confirmed by email or other writing, the Parties may reschedule all or any portion of the applicable DCQ that will not be or has not been delivered and received. In the event the Parties agree to reschedule DCQ as set forth in the preceding sentence, as part of such agreement, the Parties may elect to extend the Term by such period as may be necessary to allow for such DCQ to be supplied by Company and purchased and used by Customer (through the generation of electricity by one or more Generation Entities for Customer's benefit pursuant to the applicable Generation Agreement).

(5) Customer Use of Third Party as Agent

Customer may designate a third party (which third party may be a Generation Entity), to communicate and manage on Customer's behalf Customer's Gas purchases and the Gas supplied hereunder, including any scheduling, rescheduling and related activities. Such designation shall be provided to Company in writing.

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c. Character of Service; Interruption

(1) Efforts

The Company will deliver the applicable DCQ as set forth in Section 3(a) and (b) above, except to the extent such delivery cannot be made due to a Company Excused Interruption, a Customer Excused Event, a Company Force Majeure Event or a Customer Force Majeure Event.

(2) Interruption and Force Majeure Events

Each of the Company and the Customer acknowledge and agree that (i) in the event that the Company cannot deliver the applicable DCQ due to a Company Excused Interruption or a Company Force Majeure Event, Gas deliveries to the Customer may be interrupted or excused without liability for either Party (including the liabilities set out in the Company's tariff sections 1205d(1)(a), and 1205d(2) and (ii) in the event that the Customer does not take delivery of the applicable DCQ due to a Customer Excused Event or a Customer Force Majeure Event, the Customer shall have no obligation to take delivery of Gas or make any payments in connection therewith except as provided below..

Except as contemplated in the preceding paragraph, the failure to deliver the applicable DCQ and/or the failure to take the applicable DCQ shall result in the following liabilities for the Parties: (x) in the case of Customer where there has been a failure of Customer to take the applicable DCQ, Customer shall pay to Company the Price as set forth in Article 4 that corresponds with the DCQ of Gas that was not delivered or would have otherwise been delivered but for Customer's not having taken such Gas and (y) in the case of Company where there has been a failure of Company to deliver the applicable DCQ, Company shall pay to Customer the qualifying Interruption Expense in accordance with Section 1205 of the Company's tariff, limited to the equivalent of $2.00 per Mcf of the applicable DCQ not delivered. Each Party shall take reasonable steps to mitigate the amounts that would otherwise be owed pursuant to the above.

Further, the liability owed by either Party under this Section will be reduced for any of the applicable undelivered or untaken DCQ that is delivered pursuant to Section 3(b)(4) above.

(3) Communication

Consistent with the obligations set forth in Section 3(b)(3) above, the Company will notify the Customer in writing as soon as practical at the

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outset of any potential interruption that Company may or will curtail Gas deliveries. Consistent with the obligations set forth in Section 3(b)(3) above, the Customer will notify the Company in writing as soon as practical at the outset of any potential inability for the Customer to take Gas deliveries from the Company.

4. PRICE

a. Monthly Charges. In consideration for the services provided by the Company to the Customer, the Customer shall pay the Company each Month during the term of this agreement as follows:

(1) <u>Monthly Customer Charge</u>

Monthly Customer Charge for one Delivery Point as set out in Section 2150b of the Company's Tariff (Schedule VLFT – Very Large Firm Transportation Service).

(2) <u>Demand Charge</u>

The Demand Charge as set out in Section 2150b of the Company's Tariff (Schedule VLFT – Very Large Firm Transportation Service). For the purposes of the calculation of the Demand Charge, the Daily Contact Quantity as shown or computed in Section 3(a)(2) above for the current Contract Year shall be the Contracted Peak Demand.

(3) <u>Gas Cost</u>

The Gas delivered to the Delivery Points will be subject to all adjustments for Gas Sales Customers under the Company's tariff including, but not limited to, the Gas Cost Adjustment (Company's Tariff Sections 708 and 2301).

(4) <u>Additional Fees and Charges</u>

Service under this Special Contract will be subject to additional fees and charges as provided for in the Company's tariff including, but not limited to, the Regulatory Cost Charge as outlined in Tariff Section 2401 and applicable sales taxes.

5. INDEMNIFICATION

a. Express Limit of Obligation. By entering into this Special Contract with the Customer, the Company is not agreeing that it has any obligation, beyond the term of

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this Agreement, to sell Gas or provide Gas Sales Service to the Customer, except as contemplated otherwise herein.

b. Indemnification. The Customer will indemnify, defend, and hold the Company harmless against any and all claims by other parties, including but not limited to the Customer's electric customers, Cook Inlet purchasers, producers, Generating Entities, or pipelines, to the extent arising from the Customer's breach of this Agreement or the RCA order approving this Agreement. The Company will indemnify, defend, and hold the Customer harmless against any and all claims by other parties, including but not limited to the Company's gas customers, Cook Inlet gas purchasers, producers, Generating Entities, or pipelines, to the extent arising from the Company's breach of this Agreement, the RCA order approving this Agreement, or any applicable provision of the Company's Tariff.

c. Limitation on Damages. Except as expressly set forth in this Agreement, neither Party shall have any liability to the other for incidental or consequential damages resulting from this Agreement.

6. APPLICABILITY OF THE COMPANY'S TARIFF

a. Tariff. Except as expressly modified by this Agreement, all of the terms and conditions of the Company's Tariff shall apply to the Gas Sales Service provided under this Agreement.

b. Payment. Subject to the terms of this Agreement, the Customer agrees to the terms and conditions of payment provided in the Company's Tariff.

c. The Company's Tariff. The Customer acknowledges that it has access to the Company's Tariff and is familiar with its provisions.

7. RCA APPROVAL

a. Special Contract Subject to RCA Approval. This Agreement must be approved by the RCA before Customer purchases Gas hereunder. In accordance with 3 AAC 48.390(b)(2) this Agreement is, at all times, subject to revisions by the Commission. Company will submit this Agreement to the RCA for its consideration within five (5) business days after the Agreement has been signed by both parties. Customer must also submit any cost-of-power adjustment and obtain any other relevant approval required from the RCA in connection with this Agreement (together with Company's submission of this Agreement, the "RCA Approvals"). Company will file for approval

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of this Agreement with the RCA within five (5) business days after this Agreement has been signed by both parties.

b. Conditional RCA Acceptance; Right of Termination. If the RCA issues an order that approves (conditionally or otherwise) this Agreement and imposes terms and conditions or modifications unacceptable to Customer or Company, each as determined in its sole and absolute discretion, Customer or Company shall attempt to negotiate in good faith mutually acceptable alternative provisions within thirty (30) days of the RCA order. If the Parties cannot negotiate mutually acceptable provisions in that time period, either Customer or Company may terminate this Agreement by written notice to the other Party, such termination to take effect on the date outlined in any such written notice of termination.

c. Termination due to Lack of Timely RCA Approvals. If RCA Approvals have not been obtained within 60 calendar days after submittal, either Party may terminate this Agreement by written notice to the other Party, such termination to take effect on the date outlined in any such written notice of termination.

d. Determining Effective Date following RCA Approval. RCA Approval will be deemed to have occurred on the date that an RCA order approving this Agreement and the Customer's cost of power adjustment modification, without conditions or modifications unacceptable to the Parties, becomes final.

8. EXCUSED EVENTS AND FORCE MAJEURE

a. Excused Events.

(1) Company Excused Interruption. Company shall be excused from its obligation hereunder to deliver the applicable DCQ to the extent that it is unable to deliver such DCQ due to a Company Excused Interruption. For the purposes of this Agreement, a "Company Excused Interruption" shall mean: (1) the Company's inability to deliver all or a portion of the applicable DCQ because the demand of the Company's G1 through G4 Gas Sales Customers exceeds 270,000Mcf/d; (2) prior to initiating the curtailments contemplated in the Gas Emergency Agreement Letter of August 25, 2009 and / or the curtailments contained in § 1220 of Company's Tariff;, (3) the inability of a supplier to deliver gas contracted under Company's gas supply agreements, and (4) scheduled and unscheduled outages affecting the facilities, pipelines and related infrastructure necessary for the delivery of Gas to the Delivery Point in the volumes required to meet the applicable DCQ,

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(2) Customer Excused Event. Customer shall be excused from its obligation hereunder to take the applicable DCQ to the extent that it does not take such DCQ due to a Customer Excused Event but only to the extent that the Customer Excused Event DCQ volumes are rescheduled and taken pursuant to Section 3(b)(4) above or to the extent the Company elects to retain any Customer Excused Event DCQ volumes. For the purposes of this Agreement, a "Customer Excused Event" shall mean: (1) the inability of a Generation Entity to use the Gas to be purchased by Customer, (2) the inability to transmit electricity to Customer over the Alaska Intertie if such inability is due to a scheduled or unscheduled outage, or (3) the temporary or partial shut-down of one or more of Customer's large industrial users such that Customer's demand from the Generation Entities is reduced.

(3) Each Party shall notify the other Party in writing as soon as reasonably practicable of any Company Excused Interruption in the case of Company and any Customer Excused Event in the case of Customer and the expected duration thereof. Upon the cessation or termination of a Company Excused Interruption in the case of Company and a Customer Excused Event in the case of Customer, Company or Customer, as applicable, shall notify the other Party that it is ready to resume delivery of the applicable DCQ or resume taking delivery of the applicable DCQ, as applicable, and such delivery and/or taking of deliveries shall, unless agreed otherwise by the Parties, thereafter resume in accordance with this Agreement.

b. Force Majeure.

In addition to the other applicable provisions of the Company's tariff, the Parties agree to the application of the Company's tariff Section 1605l (Force Majeure) to this Agreement with the following modifications:

(i) The term "Shipper" as it is used in Section 1605l is to be read as "Customer".

(ii) Section 1605l(3)(f) is modified to read "explosions, breakage or accidents to machinery or lines of pipe or transmission lines or, the necessity for making repairs to or alterations of machinery or lines of pipe or transmission lines"

9. NOTICES

a. Delivery of Notices. Notices to the Customer and Company, and billings for service to the Customer shall be mailed, emailed or delivered to the addresses listed below. Telephone and facsimile numbers are provided for other communications.

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Notice shall be deemed to have been given when received by the Company or the Customer at those addresses.

FOR THE COMPANY:
For Scheduling and Day to Day Operations:
ENSTAR Natural Gas Control
ATTN: Gas Control
Physical Address:
401 E. International Airport Road
Anchorage, AK 99518
Mailing Address:
P.O. Box 190288
Anchorage, AK 99519-0288
Telephone: 907 334-7788
Facsimile: 907 334-7779
E-mail: EnstarGasControl@enstarnaturalgas.com

For Payments:

ENSTAR Natural Gas Company
ATTN: Manager of Gas Accounting
Physical Address:
3000 Spenard Road
Anchorage, AK 99503
Mailing Address:
P.O. Box 190288
Anchorage, AK 99519-0288
Telephone: 907 334-7628
Facsimile: 907 272-3403
E-mail: denise.romans@enstarnaturalgas.com

For all other Notices:

ENSTAR Natural Gas Company
Attention: Director Gas Supply Operations
Physical Address:
3000 Spenard Road
Anchorage, AK 99503
Mailing Address:
P. O. Box 190288
Anchorage, AK 99519
Telephone: (907) 334-7830
Facsimile: (907) 334-7657
E-mail: inna.johansen@enstarnaturalgas.com

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FOR THE CUSTOMER:

For Scheduling and Day to Day Operations:

Golden Valley Electric Association, Inc.
ATTN: Power Systems Manager
Physical Address: 758 Illinois Street
Fairbanks, AK 99707
Mailing Address:
PO Box 71249
Fairbanks, AK 99707-1249
Telephone: 907-458-5821
Facsimile: 907-458-6370
E-mail: PHSarauer@gvea.com

For Payments:

Golden Valley Electric Association, Inc.
ATTN: Accounts Payable
Physical Address: 758 Illinois Street
Fairbanks, AK 99707
Mailing Address:
PO Box 71249
Fairbanks, AK 99707-1249
Telephone: 907-322-0212
Facsimile: 907-458-6382
E-mail: ap@gvea.com, AJLynch@gvea.com

For all other Notices:

Golden Valley Electric Association, Inc.
ATTN: Power Systems Manager
Physical Address: 758 Illinois Street
Fairbanks, AK 99707
Mailing Address:
PO Box 71249
Fairbanks, AK 99707-1249
Telephone: 907-458-5821
Facsimile: 907-458-6370
E-mail: PHSarauer@gvea.com

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b. Updating of Notice Contacts. The Company and the Customer agree to provide prompt written updates to the contacts listed in Section 9(a) in the event there is a change.

10. MISCELLANEOUS PROVISIONS

a. Binding Upon Successors. This Agreement shall be binding upon and inure to the benefit of the legal representatives, successors and assigns of the parties. Except as provided below, neither Party may assign its rights and obligations under the Agreement without first obtaining the written consent of the other. Consent is not required if all or substantially all of the assets of the Company or the Customer are acquired by another person or the Company or the Customer is merged, consolidated or reorganized with another person, provided that the assignee assumes in writing the assignor's obligations under this Agreement. An adoption notice (in writing) for the Company's Tariff by an assignee or successor, or a reissuance of the Company's tariff in the name of the assignee or successor, with this Special Contract listed on the Schedule of Special Contracts in the Tariff shall be considered sufficient written proof of the assignee or successor assuming the Company's obligation under this Agreement. Nothing contained in this Article shall prevent either Party from pledging or mortgaging its rights under the Agreement for security of its indebtedness.

b. Choice of Law. This Agreement shall be governed by and construed in accordance with the laws of the State of Alaska. Jurisdiction and venue for filing any lawsuits concerning this Agreement shall be in the Superior Court for the State of Alaska, the Third Judicial District, at Anchorage.

c. Agreement Not to be Construed Against Either Party as Drafter. The Parties recognize that this Agreement is the product of the joint efforts of the parties, that each Party has had the benefit of the counsel of their choice, and agree that it shall be construed according to its plain meaning and shall not be construed against either Party as drafter.

d. Entire Agreement. This Agreement, and Attachments, constitutes the entire Agreement and understanding between the parties concerning the subject matter of this transaction, and all prior agreements, understandings and representations, whether oral or written, concerning this subject matter are superseded by this written Agreement. No amendment to this Agreement shall be binding on either Party until reduced to writing and signed by the parties.

e. No Intended Third-Party Beneficiary. The Parties understand and agree that no person or entity is an intended third-party beneficiary of this Agreement.

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11. EQUAL OPPORTUNITIES CLAUSE. As applicable, the Customer shall abide by the requirements of 41 CFR 60-1.4(a), 60-300.5(a) and 60-741.5(a). These regulations prohibit discrimination against qualified individuals based on their status as protected veterans or individuals with disabilities, and prohibit discrimination against all individuals based on their race, color, religion, sex, sexual orientation, gender identity, national origin, and for inquiring about, discussing or disclosing compensation. Moreover, these regulations require that covered contractors take affirmative action to employ and advance in employment individuals without regard to race, color, religion, sex, sexual orientation, gender identity, national origin, disability or veteran status. The Customer must notify the Company in writing in the event of its noncompliance with this provision, and the Company may terminate or suspend in whole or in part this Agreement and the Company may declare the Customer ineligible for further Company contracts.

IN WITNESS WHEREOF, the parties have executed this Agreement.

ENSTAR Natural Gas Company, a division of SEMCO Energy, Inc.	**Golden Valley Electric Association, Inc.**
John Sims	John Burns
Name	Name
President	President & CEO
Title	Title
Signature	Signature
1/13/2023	01/13/2023
Date	Date

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ATTACHMENT A
Delivery Point(s)

The following Delivery Points are authorized under this Agreement. Unless otherwise agreed by the Parties, Seller may deliver Gas sold under this Agreement at any Delivery Point listed herein. This Attachment may be updated from time to time by agreement of both Parties.

1. **Beluga Pipeline Company Connection (ENSTAR/APC Station B605, Meters 700 & 701, BLPC Nos. 8101 & 8102)**
   At the upstream flange of Alaska Pipeline Company's meter at or near the connection of Alaska Pipeline Company's Beluga-Anchorage pipeline and Kenai Beluga Pipeline's Granite Point-Beluga pipeline located within the West 1/2 of the Southwest 1/4 of Section 26, Township 13 North, Range 10 West, Kenai Peninsula Borough, Seward Meridian, State of Alaska.

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ATTACHMENT B– GENERATION ENTITY (ENTITIES)

This Attachment may be updated from time to time by agreement of both Parties.

1. **Chugach Electric Association, Inc.**

Contact(s):
Manager of Fuel Supply and Operations
Kevin Skiba
907-762-4760
kevin_skiba@chugachelectic.com

RECEVED

By the Regulatory Commission of Alaska on Dec 28, 2022

From:	White, John D (RCA)
To:	RCA Records & Filing
Subject:	FW: [EXTERNAL] TA359-13
Date:	Wednesday, December 28, 2022 3:17:32 PM
Attachments:	GVEA"s Filing in Compliance with Commission Order No. U-22-029(3).pdf 12 27 22 GVEA CEA MOU - signed.pdf

Dear R&F,

Could you please enter the below email, as well as the attachment to the record for TA359-13.

Thank you,

John

From: Daniel A. Heckman <DAHeckman@gvea.com>
Sent: Wednesday, December 28, 2022 12:49 PM
To: White, John D (RCA) <john.white1@alaska.gov>
Subject: RE: [EXTERNAL] TA359-13

CAUTION: This email originated from outside the State of Alaska mail system. Do not click links or open attachments unless you recognize the sender and know the content is safe.

Mr. White –

This email contains GVEA's responses to your questions below in blue. Should you have need of any additional information or have further questions, please advise. Regarding GVEA's Strategic Generation Plan, I am providing a courtesy copy of GVEA's filing in compliance with Commission Order No. U-22-029(3), where a similar request was made. As stated in GVEA's response, GVEA's Strategic Generation Plan sets out the general framework and vision for GVEA's future generation strategy, however, it is not a single, formal planning document or formal plan. GVEA's compliance filing provides information and supporting documents requested by the Commission previously on the Strategic Generation Plan.

1. Reading the MOU, it appears that Chugach is currently providing the gas for the generation in the agreement, is this correct?

   Under the terms of the 2019 MOU, the gas can either be provided by Chugach at contract price or by GVEA. Currently under this MOU, Chugach is providing the gas for generation, if available. Upon approval of the ENSTAR Agreement, GVEA will be providing gas for the generation with consistent availability and pricing to our Members.

2. Will the agreement with Enstar supplement or replace the energy generated under the MOU.

   Under the terms of the revised MOU, the gas from the ENSTAR Agreement is not expected to replace the energy generated under this MOU. Instead, it will replace the gas provided by

Chugach with gas provided by GVEA. GVEA has the option under the MOU to provide it's own fuel and the agreement with ENSTAR is consistent with the intent and plain language of that portion of the MOU.

3. Do you know when the modification will happen, and or, what the anticipated modification is.

   Attached is a copy of the MOU Amendment signed and executed by GVEA and Chugach. The modification has taken effect, however, as noted under the ENSTAR Agreement, the effective date of that Agreement is the third business day following the later of (i) RCA Approvals, and/or (ii) the effective date of the Generation Agreements entered into by GVEA and Chugach. The events in both (i) and (ii) must have occurred prior to the effective date. During the three business days following the later of the events in (i) or (ii), Chugach, ENSTAR, and GVEA will work to finalize the daily nomination, dispatch, tracking, and reporting processes and procedures.

Thank you.

Daniel Heckman

Daniel A. Heckman | Regulatory Manager
Golden Valley Electric Association, Inc.
758 Illinois St. | Fairbanks, AK 99701
Office: (907) 458-5706 (Direct)
daheckman@gvea.com | www.gvea.com

From: White, John D (RCA) <john.white1@alaska.gov>
Sent: Tuesday, December 27, 2022 10:58 AM
To: Daniel A. Heckman <DAHeckman@gvea.com>
Subject: [EXTERNAL] TA359-13

Mr. Heckman,

Earlier I sent an email requesting the agreement between GVEA and Chugach to generate the power on GVEA's behalf, I would also like to request a copy of the Strategic Generation Plan adopted by the GVEA Board on June 27, 2022, referenced on page 2 of the TA359.
I also note the reference on Page 2 to a GVEA and Chugach MOU, filed in July 2019, which states the

terms of the MOU are being modified.

1. Reading the MOU, it appears that Chugach is currently providing the gas for the generation in the agreement, is this correct?
2. Will the agreement with Enstar supplement or replace the energy generated under the MOU.
3. Do you know when the modification will happen, and or, what the anticipated modification is.

Thank you,
John

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners:	Keith Kurber II, Chairman Robert A. Doyle Robert M. Pickett Daniel A. Sullivan Janis W. Wilson

In the Matter of the Tariff Revision Designated as TA353-13 Filed by GOLDEN VALLEY ELECTRIC ASSOCIATION, INC. for Interconnection with Delta Junction Renewable Resources, LLC	)))))	U-22-029

GOLDEN VALLEY ELECTRIC ASSOCIATION, INC'S FILING IN COMPLIANCE WITH COMMISSION ORDER U-22-029(3)

On July 1, 2022, the Regulatory Commission of Alaska (Commission) issued Order U-22-029(3) in the above referenced docket. The Order required:

1. By no later than 10:00 a.m. on July 6, 2022, Golden Valley Electric Association, Inc. shall file in this docket a copy of its Strategic Generation Plan approved by the Board of Directors on June 27, 2022, including all supporting documents, data, and modelling runs.
2. By 10:00 a.m. on July 6, 2022, Golden Valley Electric Association, Inc. shall be prepared to address when it will be able to file a revised *Delta Junction Renewable Resources: Avoided Cost Study* based on the assumptions and scenarios set out in the Strategic Generation Plan approved by the Board of Directors on June 27, 2022.

Based on the Commission's request, Golden Valley Electric Association, Inc. (GVEA), hereby provides the following information and documents in compliance with the Commission Order U-22-029(3).

Background

On September 28, 2020, GVEA's Board of Directors adopted a Strategic Directive regarding the evaluation of GVEA's generation portfolio. The Strategic Directive provided:

> Generation Portfolio: Recognizing GVEA's aging generation fleet and evolving regulatory landscape, create, recommend and implement as approved, a future generation strategy that utilizes proven generation and demand side technologies on a GVEA owned or purchased (locally or on a Railbelt) basis to optimally balance fuel and life cycle cost, emissions reduction, load, reliability, fuel resource and time frame criteria.

The Strategic Directive began in part due to GVEA's aging infrastructure. As discussed in prior matters before the Commission, GVEA has also been faced with the decision on whether to retire Healy Unit 1, or to install Selective Catalytic Reduction (SCR) emission controls, at an estimated cost of approximately $26.1 million dollars to allow for the continued operation of the unit. A 2012 Consent Decree between GVEA and the Environmental Protection Agency required this decision to be made no later than December 31, 2022, with the implementation to occur by December 31, 2024.

Over the past 18 months, GVEA's Board, staff, and consultants spent hundreds of hours developing modeling for over 120 different generation scenarios in response to the Strategic Generation Directive. These scenarios looked at the potential implications and risks associated with a range of different viable generation options.

In tandem with the Strategic Generation Directive, the work group also took the opportunity to model and review associated emission impacts for the various generation scenarios, keeping in mind the Carbon Reduction Goal set by GVEA in 2018 to reduce carbon emissions 26% by 2030 without any adverse long-term impacts on rates.[1] A number of GVEA members have expressed support for transitioning to a more carbon neutral generation mix throughout the Strategic Generation development process. In addition, Industrial users across the nation are implementing aggressive carbon reduction plans, including industrial users within GVEA's service territory.

On June 27, 2022, GVEA's Board adopted the broad components of a Strategic Generation Plan that is geared towards maintaining system reliability, reducing member rates, and reducing emissions. The plan consisted of five components:

1. GVEA to install a selective catalytic reduction system on Healy Unit 1;
2. GVEA's management team to develop a comprehensive plan within 90 days for the systematic retirement of Healy Unit 2 by December 31, 2024;
3. GVEA to develop and issue a Request for Proposal (RFP) for a large-scale wind resource Power Purchase Agreement within 60 to 90 days;
4. GVEA to expeditiously move forward within 90 days for the purchase and installation of a new Battery Energy Storage System of a minimum size of 46 megawatts /184 megawatt hours; and
5. GVEA to secure a Purchase Power Agreement from southcentral Alaska utility/utilities or from southcentral gas producers/suppliers for the equivalent of 30 to 50 megawatts of energy to be transmitted up the Alaska Intertie.

With the adoption of these items, authorization and direction has been given to GVEA staff to develop and take the actions necessary to fully build out a recommended plan and to

[1] Carbon Reduction Goal Policy: Reduce GVEA's CO2 emissions rate (measured by tons per MWH) by 26% over the 2012 emissions rate by 2030 with no adverse long-term impact on rates.

pursue firm proposals on several of the above components within a 90-day period. While the plan adopted by the Board set the course for staff and GVEA's members, there are a number of variables that staff must further develop and refine and that will ultimately require separate approval from GVEA's Board, the Commission, and potentially from GVEA's financiers during the process.

GVEA's Board recognized that the June 27th decision was a starting point and that while it gave a firm vision and direction for what GVEA's future generation would look like, significant work, planning, assessment and challenges still remain over the next couple years to make this vision a reality. GVEA has implemented an internal team to focus on the Board's adopted plan with the goal of providing a full report to GVEA's Board in September 2022.

Commission Requests

As part of this docket, the Commission required GVEA to file various documents and information related to GVEA's newly adopted Strategic Generation Plan. GVEA addresses each of these requests in turn:

Request 1: By no later than 10:00 a.m. on July 6, 2022, Golden Valley Electric Association, Inc. shall file in this docket a copy of its Strategic Generation Plan approved by the Board of Directors on June 27, 2022, including all supporting documents, data, and modelling runs.

Response: As noted above, GVEA's Board of Directors adopted a "Strategic Generation Plan," that sets out the general framework and vision for GVEA's future generation strategy, however, it is not a single, formal planning document or formal plan as the Commission may be referencing. Rather, the planning process involved significant modeling that formed the basis for the Board's decision, some of which aligned with the Board's ultimate adopted plan, while others evaluated different generation scenarios such as the addition of an LM6000, the addition of solar, or other options that were ultimately not selected, but were still considered as part of the Board's decision. In total, there were approximately 120 separate modeling scenarios performed and evaluated throughout the planning process.

Consistent with the Commission's Order, GVEA is providing the following responsive documents as they related specifically to the Strategic Generation Plan adopted by GVEA's Board:

1. The Motion to Adopt a Strategic Generation Plan as passed by the Board during the June 27, 2022 Special Public Board Meeting (Attachment A);
2. The presentation developed, provided and discussed by consultant Mike Hubbard of Financial Engineering Company, during the June 27, 2022 Special Board Meeting. The presentation provides a high level discussion of the methodology used, resources investigated, and evaluation criteria, and provides a summary of the cost and emission impacts of a number of the different modeling scenarios run (Attachment B);
3. An Excel Model developed by Mr. Hubbard used during the Strategic Generation analysis that provides a summary of information regarding the various case studies and the associated summaries, scenarios, charts, emissions, costs and other factors utilized during the process. Consistent with Commission Order U-22-029(2) this file is Confidential and will be provided under seal with the Commission. The file will also be provided to involved parties upon their filing of a Non-Disclosure Agreement in this matter.

GVEA provides the runs that most closely aligned with the ultimately adopted Strategic Generation Plan, rather than a single case given that variables such as the final size of a battery, wind, and power purchase agreement are still being developed by GVEA staff during the 90-day period requested by the Board. Modifications to any of these items will have an impact on purchase rates within an avoided cost study. While GVEA is confident based on the modeling and assumptions generated to date, that the Strategic Generation Plan will provide significant benefit to our members, GVEA is not yet at the point to be able to definitively provide final cost, capacity, and start dates for these various aspects of the plan, which are still under development. GVEA anticipates that many, if not all, of these generation changes would not be in place until approximately 2025. As noted above, there are additional non-responsive generation runs that are not consistent with the plan adopted by GVEA's Board that are not being filed in this matter, however, they would have all been used in the overall assessment of the Strategic Generation Plan.

Request 2: By 10:00 a.m. on July 6, 2022, Golden Valley Electric Association, Inc. shall be prepared to address when it will be able to file a revised *Delta Junction Renewable Resources: Avoided Cost Study* based on the assumptions and scenarios set out in the Strategic Generation Plan approved by the Board of Directors on June 27, 2022.

Response:

The Strategic Generation Plan does not consist of a single, definitive planning document based on a single generation modeling run because the broad outline provided in the Strategic Generation Plan includes a number of the items that are not definitive (e.g. the size, cost, and timing of the generation resource).

Given the complexities associated with the Strategic Generation Plan, GVEA requires at least four weeks to provide a revised Avoided Cost Study, as requested by the Commission. As previously noted, within the next 90 days, GVEA expects to further develop the Strategic Generation Plan, which will include developing more certain data related to pricing, timeline and size of several key plan components. There are also components of the plan such as the retirement of Healy 2 that will take longer to evaluate and analyze with certainty in order to confirm those aspects can move forward as proposed in the Board's plan given that separate approval would be needed from both the Commission and GVEA's financiers related to the debt treatment before GVEA could definitively retire the plant.

Conclusion

GVEA appreciates the opportunity to clarify the nature of its Strategic Generation Plan and submits the attached documents responsive to the Commission's request. GVEA will have a number of staff and consultants available during the July 6, 2022 Prehearing Conference that can provide additional details or respond to further questions related to these requests.

DATED July 6, 2022, at Portland, Oregon.

McDowell Rackner Gibson PC

By: /s/ Adam Lowney

Adam Lowney
McDowell Rackner Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205
Phone: (503) 595-3926
Email: adam@mrg-law.com
Oregon Bar No. 053124

CERTIFICATE OF SERVICE

I hereby certify that on July 6, 2022, a true and correct copy of **Golden Valley Electric Association, Inc.'s Filing in Compliance with Commission Order U-22-029(3)** was served via e-mail on the following:

Office of the Attorney General
Jeffrey Waller, Chief Assistant Attorney General,
JC Croft, Assistant Attorney General
Deb Mitchell
Amber Henry, Law Office Assistant
Regulatory Affairs & Public Advocacy
1031 West Fourth Avenue, Suite 200
Anchorage, AK 99501
Email: jeff.waller@alaska.gov
JC.Croft@alaska.gov
deborah.mitchell@alaska.gov
amber.henry@alaska.gov

Delta Junction Renewable Resources, LLC
Brian Solan, PE/Bus Dev Mgr
Elizabeth Simon, Asst General Counsel
Ameresco, Inc.
6643 Brayton Drive
Anchorage, AK 99507
Email: bsolan@ameresco.com
esimon@ameresco.com

/s/ Daniel Heckman
Daniel Heckman
Regulatory Manager

:

Strategic Generation Motions

Special Board Meeting: June 27, 2022

Motion #1: Adopting a Strategic Generation Plan

I move that GVEA's Board of Directors Adopt a Strategic Generation Plan consisting of the following components:

1. GVEA to install a Selective Catalytic Reduction system on Healy Unit 1;
2. GVEA's management team develop a comprehensive plan within 90 days for the systematic retirement of Healy Unit 2 by December 31, 2024;
3. GVEA develop and issue a Request for Proposal for a large-scale wind resource Power Purchase Agreement within 60 to 90 days;
4. GVEA to expeditiously move forward within 90 days for the purchase of a new Battery Energy Storage System of approximately 46 megawatts /184 megawatt hours in size; and,
5. GVEA to secure a Purchase Power Agreement from a Southcentral Alaska utility or utilities, or from Southcentral gas producers or suppliers for the equivalent of 30 to 50 megawatts or the energy to be transmitted up the Alaska Intertie.

Motion #2 - Motion for Installation of the SCR on Healy Unit 1

Based on the adoption of the Strategic Generation Plan that includes installation of an SCR on Healy Unit , I move that the Board of Directors approve GVEA's CEO to execute a contract in an amount not to exceed $26.1M for the installation of SCR controls on Healy Unit 1.

At the Crossroads in GVEA Generation

the Financial Engineering Company

June 27, 2022

Where We Are

- Over the past year, GVEA has initiated a series of investigations into its power supply
- These investigations were initially commenced due to decisions that must be made regarding Healy 1 and GVEA's Battery Energy Storage System (BESS)
- As worked progressed, it became apparent that recent advancements in renewable energy technologies could offer both short- and long-term benefits
- Tonight's presentation summarizes these investigations and findings

Methodology - General

- Key to this analysis has been the use of GenTrader, a computer program that simulates the GVEA generation system
  - Hourly basis
  - 2023 – 2044 study period
- Approximately 120 scenarios have been evaluated using various assumptions regarding fuel prices, loads, unit availabilities and additional potential resources
- Economics and emissions of these scenarios have been projected while taking into account risk and opportunities

Resources Investigated

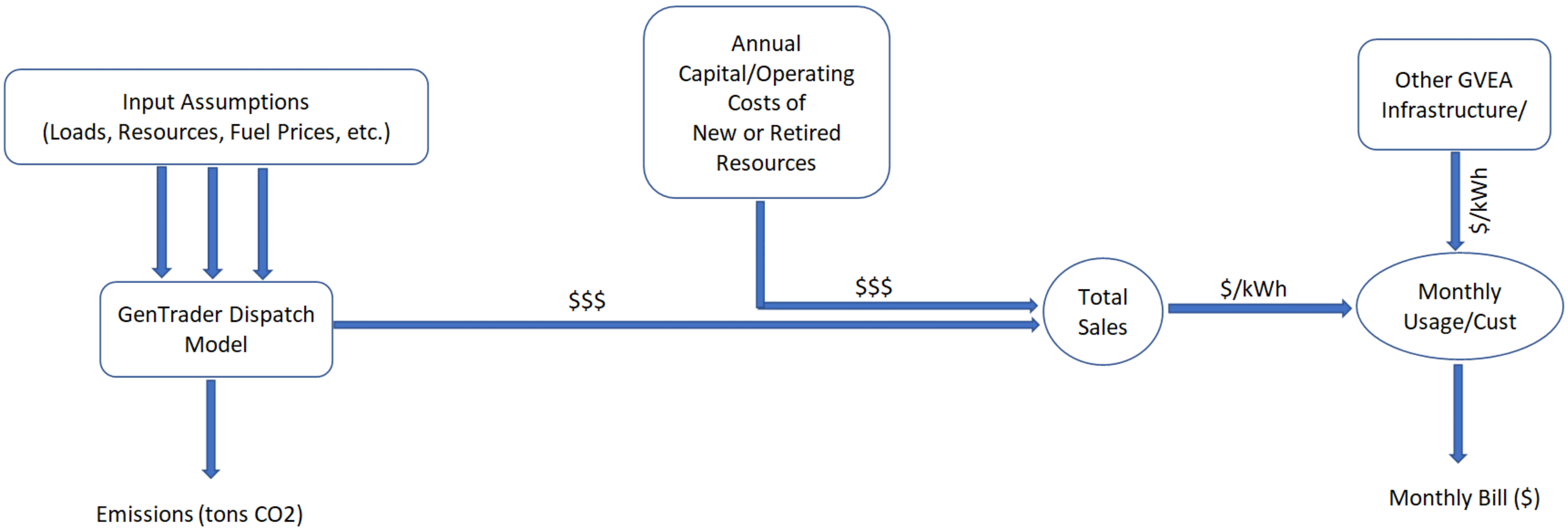
- Adding a new gas turbine to double the capacity of the existing combined cycle resource
- New solar installations of 15 and 30 MW
- New wind installations of 15 – 260 MW
- Six separate BESS configurations
- Upgrade to the Anchorage – Healy Intertie
- Purchase of gas-fired generation from the South
- Retirement of:
  - Healy 1
  - Healy 2

Resources Not Included

- Gas line, nuclear, and hydro units such as Susitna were not included due to the uncertainty and long lead time

Evaluation

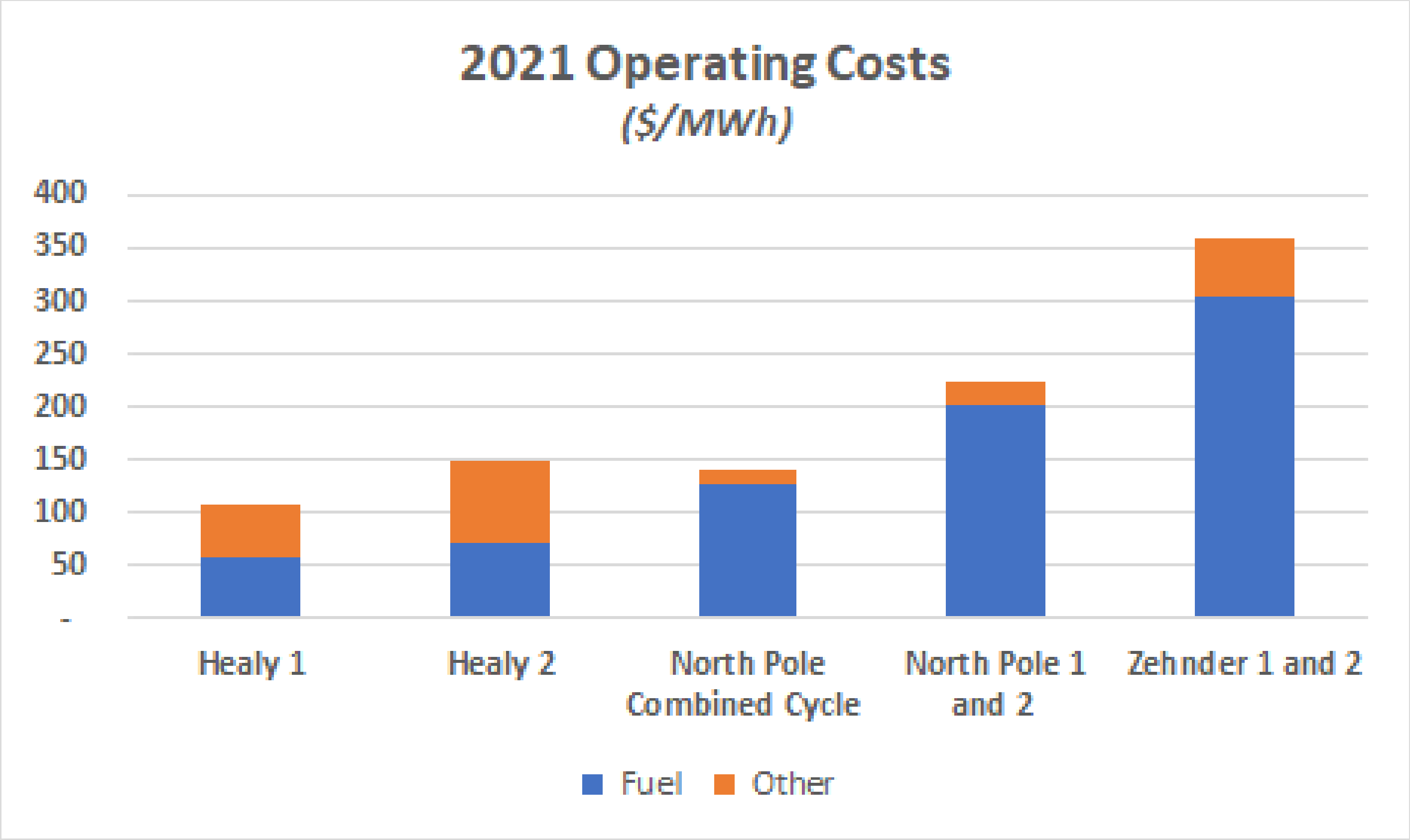
- Economic
  - Monthly bill to the average Residential user was projected and comprised of:
    - Fuel costs
    - Purchased power costs
    - Capital and operating costs of the new resources being evaluated
    - Other GVEA system costs (admin, distribution, transmission, other production, etc.)
- Emissions
  - Total CO_2 emissions over the study period


Input Assumptions
(Loads, Resources, Fuel Prices, etc.)
GenTrader Dispatch Model
Emissions (tons CO2)
$$$
Annual Capital/Operating Costs of New or Retired Resources
$$$
Total Sales
$/kWh
Other GVEA Infrastructure/
$/kWh
Monthly Usage/Cust
Monthly Bill ($)

Immediate Decisions

- Air Quality Operating Permit for Healy 1 requires pollution control equipment to be installed by 1/1/2025
  - Should an SCR be installed at a cost of approximately $25 million or should the unit be retired?
- The existing Battery Energy Storage System (BESS) is aging and requires upgrades
  - Should the existing BESS be abandoned, upgraded, or replaced with newer technololgy that can be used for regulation of renewable resources?

A Snapshot of GVEA's Thermal Resources



Healy Units

	Healy 1	Healy 2
2021	89%	68%
2020	96%	65%
2019	85%	72%
2018	93%	31%

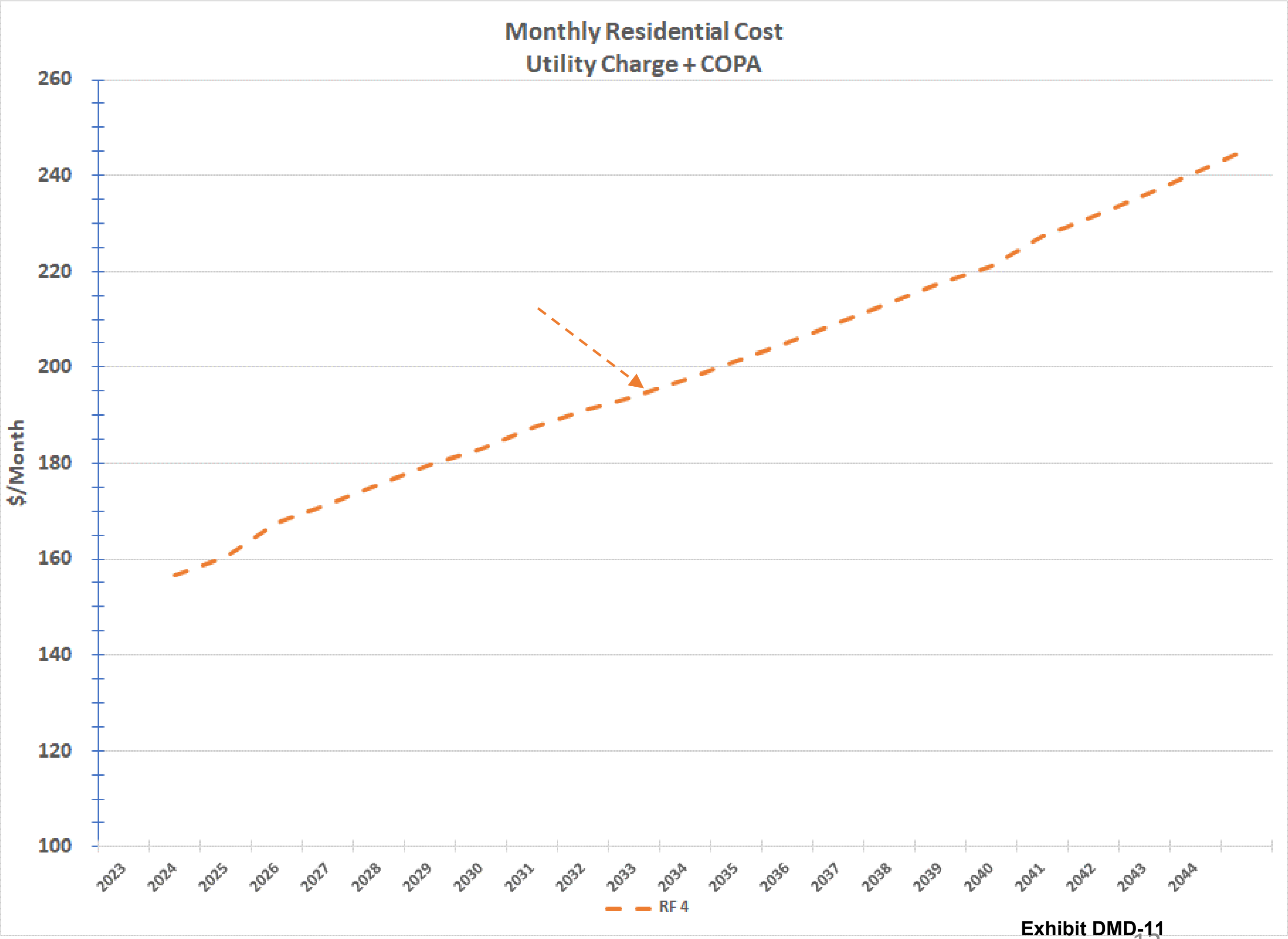
- Healy 1
  - “Workhorse” of GVEA’s fleet
  - Very high reliability and proven track record
- Healy 2
  - Has not lived up to its expected reliability even with capital improvements
  - High operating costs and not expected to decrease
  - Implications must be worked through regarding GVEA equity if retired

Summary of Findings

Existing Generation – No Retirements

Emissions (10^6 tons)

RF 4	22.9

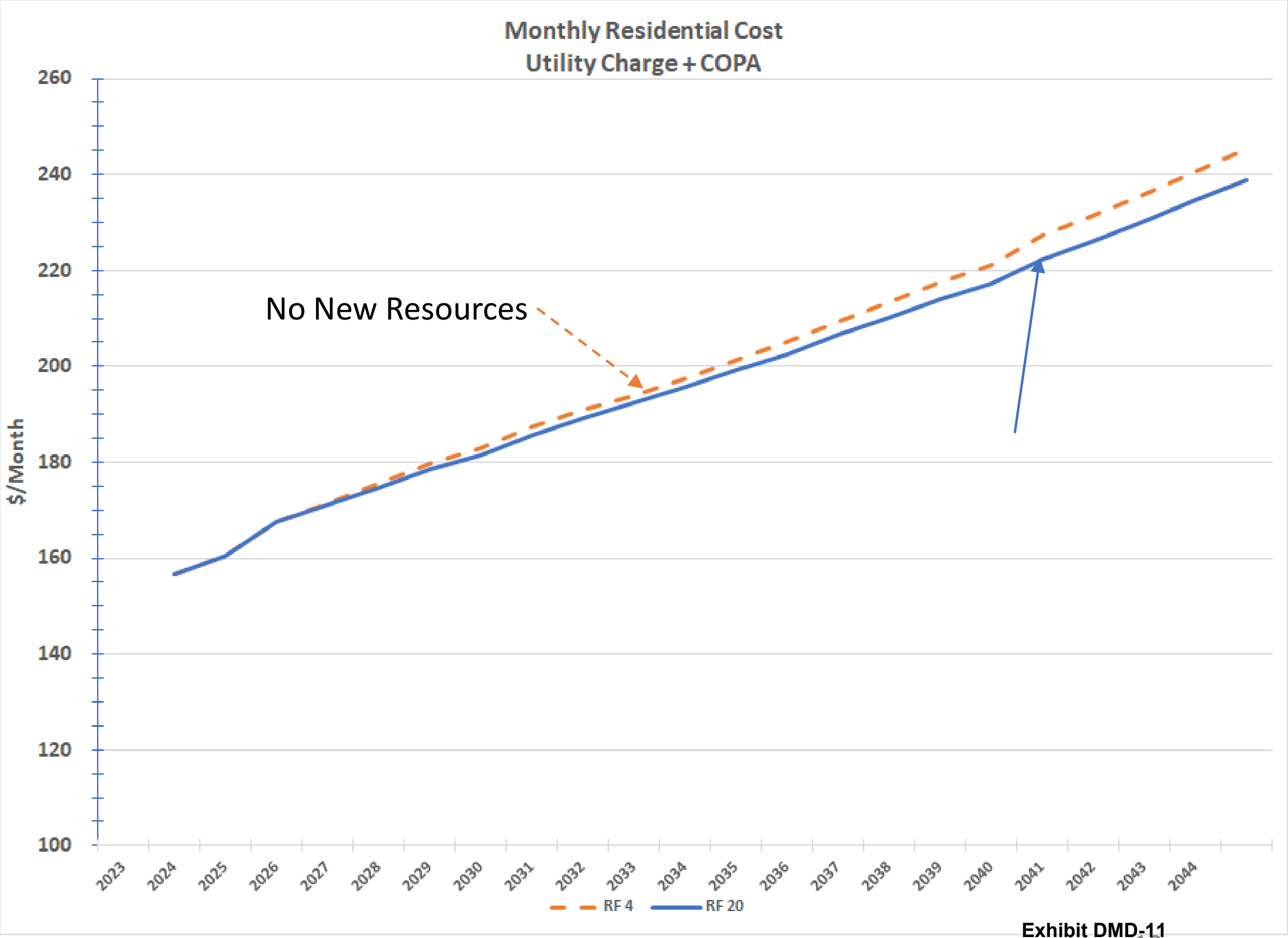


Existing Generation – No Retirements

- Increasing the capability of the combined cycle can lower costs but only a small amount
  - Susceptible to fuel price volatility

Emissions (10^6 tons)

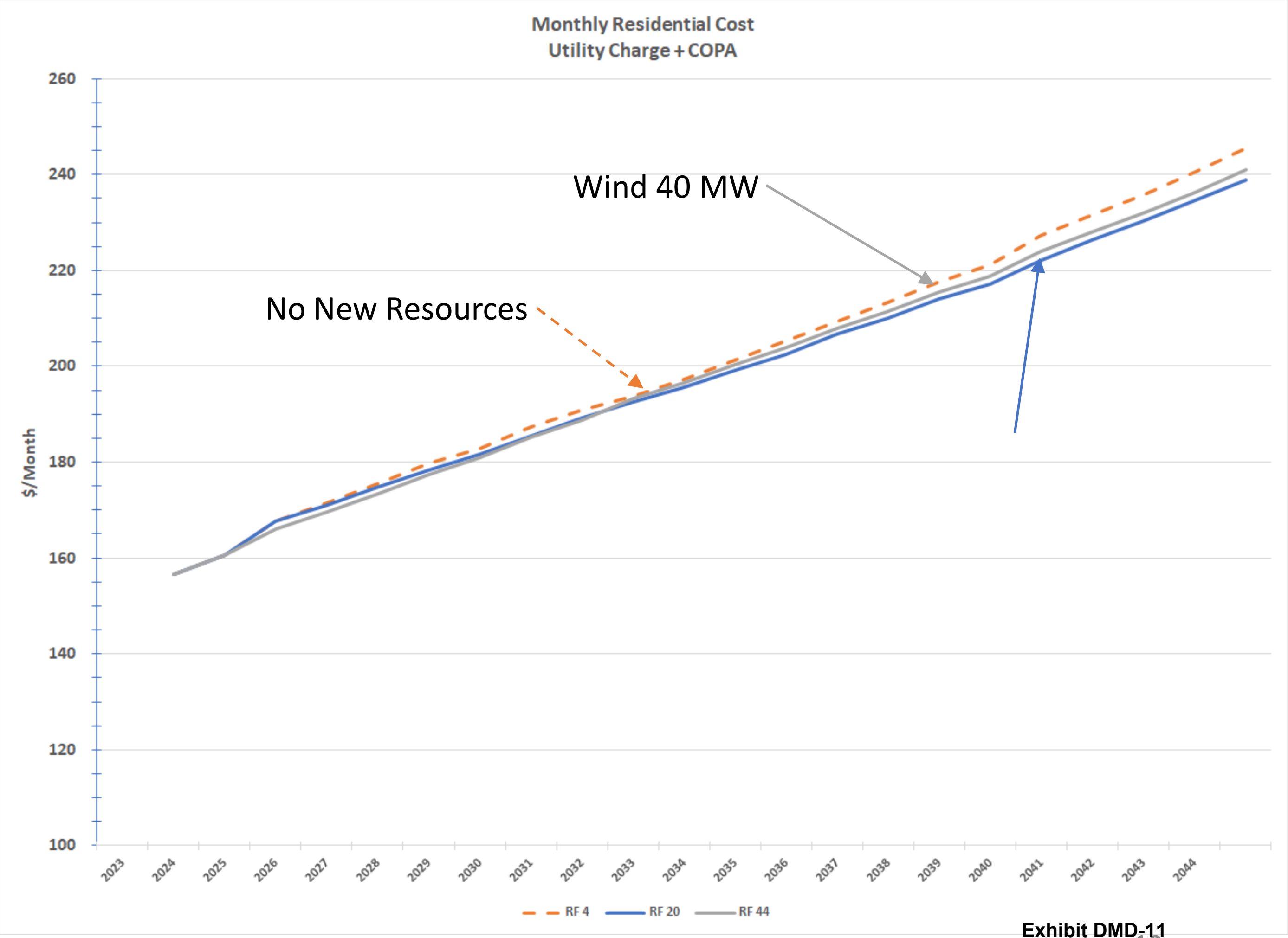
RF 4	22.9
RF 20	22.0



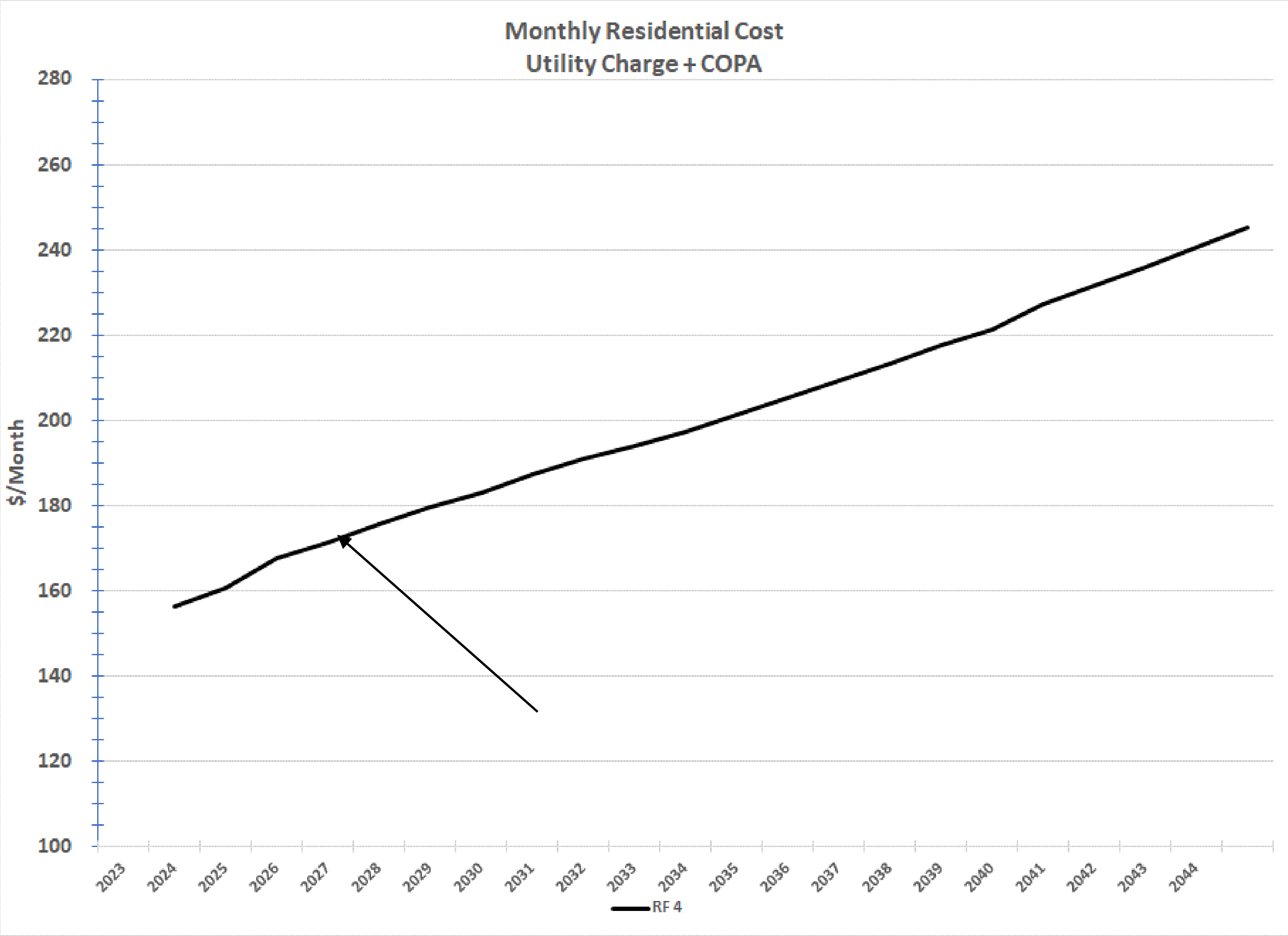
Existing Generation – No Retirements

- Increasing the capability of the combined cycle can lower costs but only a small amount
  - Susceptible to fuel price volatility
- Any scenario with no Healy retirements results in high emissions

Emissions (10^6 tons)	
RF 4	22.9
RF 20	22.0
RF 44	20.4



Healy 1 Retirement

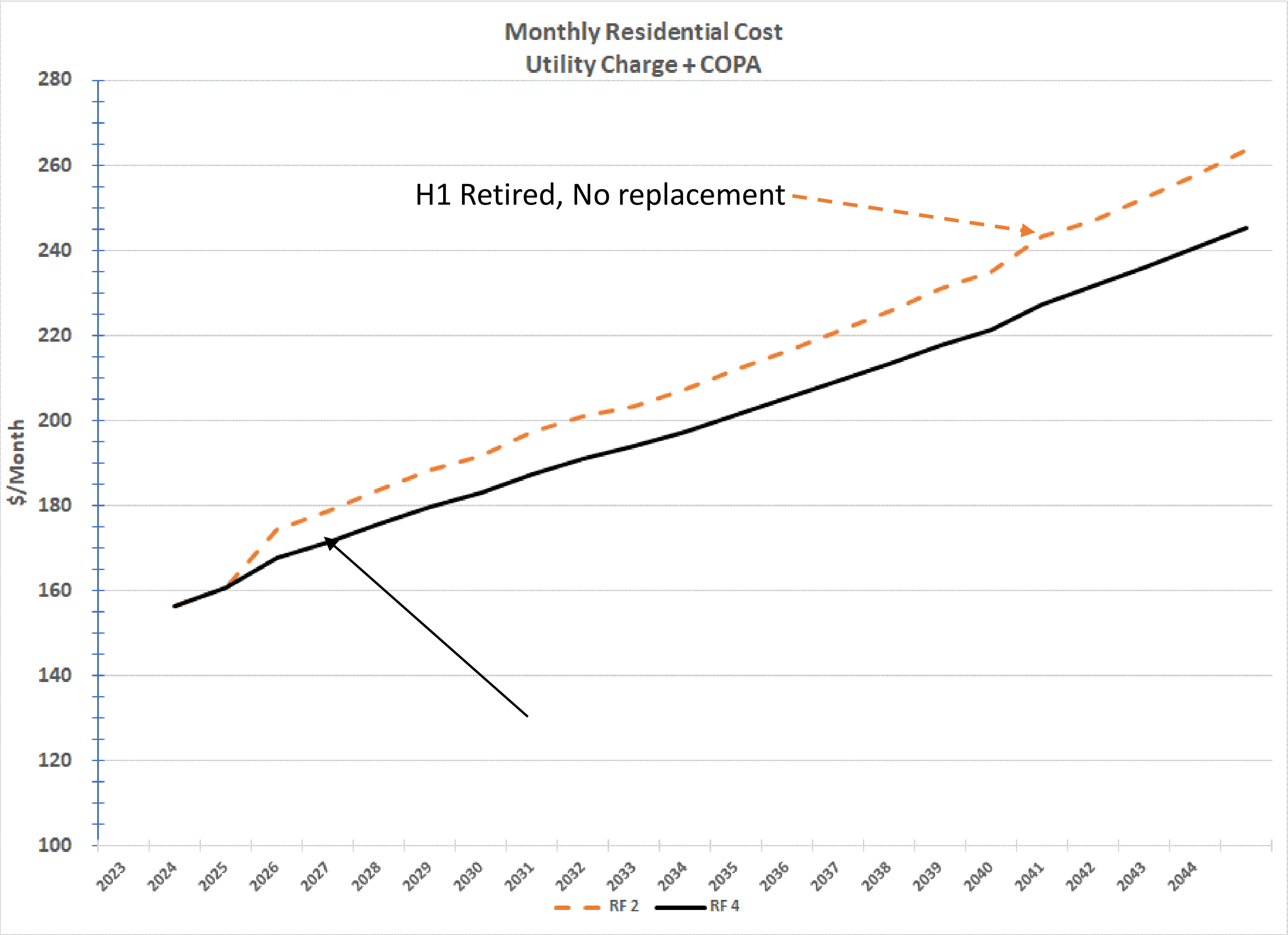


Emissions (10^6 tons)

RF 4	**22.9**

Healy 1 Retirement

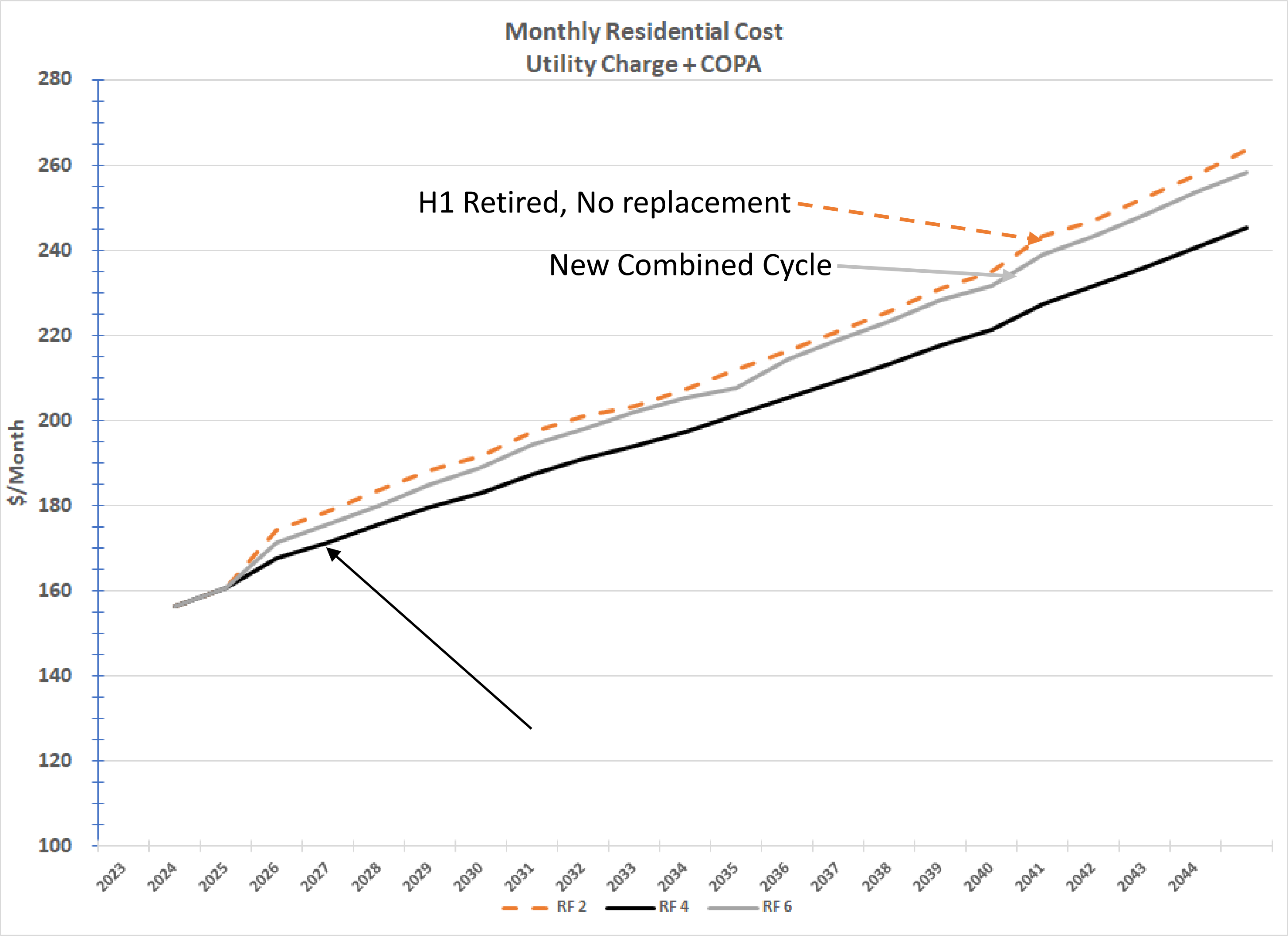
- Retirement with no replacement power adds significant costs to system



Emissions (10^6 tons)	
RF 2	20.9
RF 4	22.9

Healy 1 Retirement

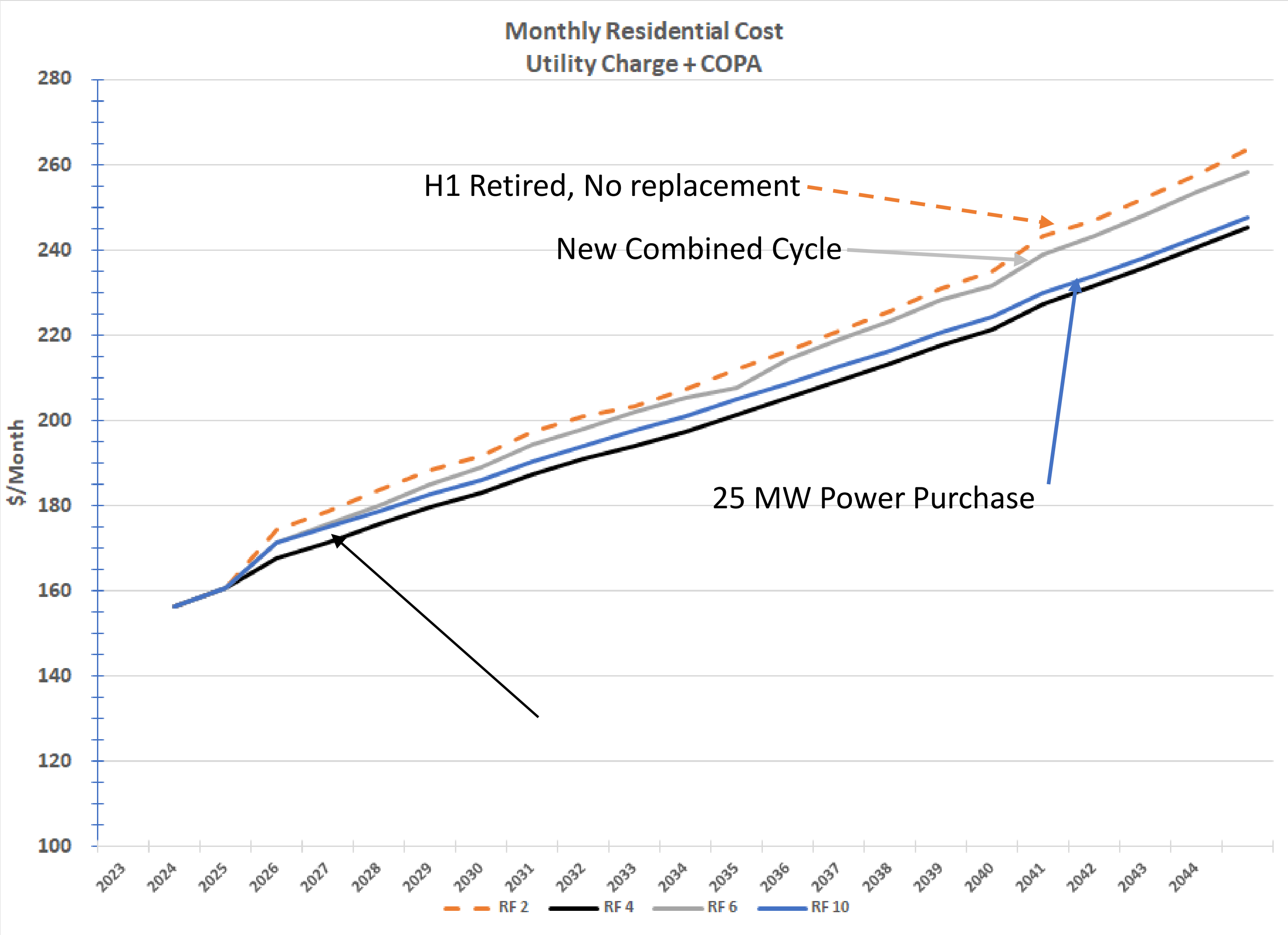
- Retirement with no replacement power adds significant costs to system
- New combined cycle higher than no retirement



Emissions (10^6 tons)	
RF 2	20.9
RF 4	22.9
RF 6	20.0

Healy 1 Retirement

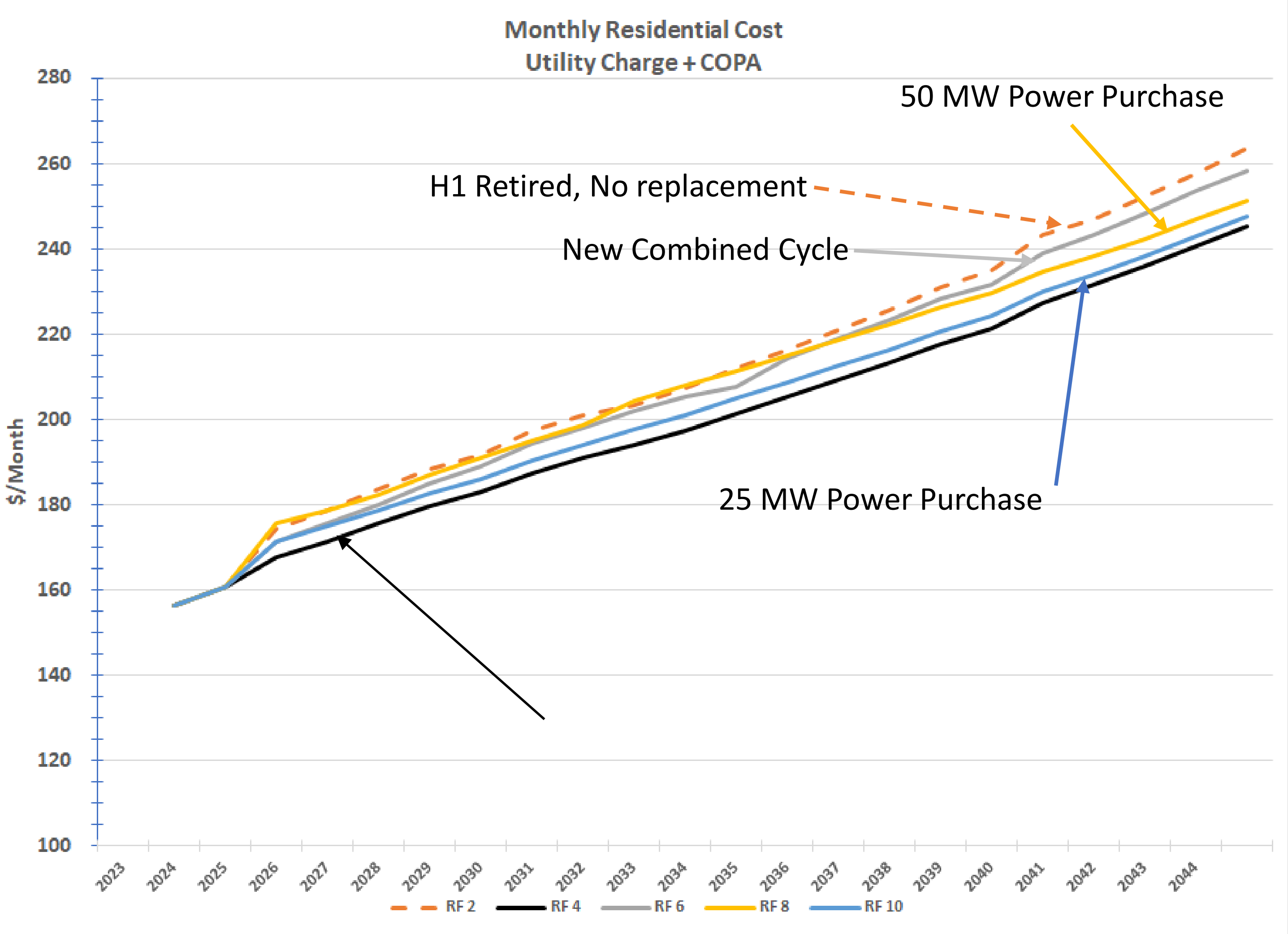
- Retirement with no replacement power adds significant costs to system
- New combined cycle higher than no retirement
- With just replacement power from south, a smaller purchase amount results in lower cost of power



Emissions (10^6 tons)	
RF 2	20.9
RF 4	22.9
RF 6	20.0
RF 10	19.3

Healy 1 Retirement

- Retirement with no replacement power adds significant costs to system
- New combined cycle higher than no retirement
- With just replacement power from south, a smaller purchase amount results in lower cost of power – difficult to fit 50 MW in with loss of only 25 MW (Healy 1)

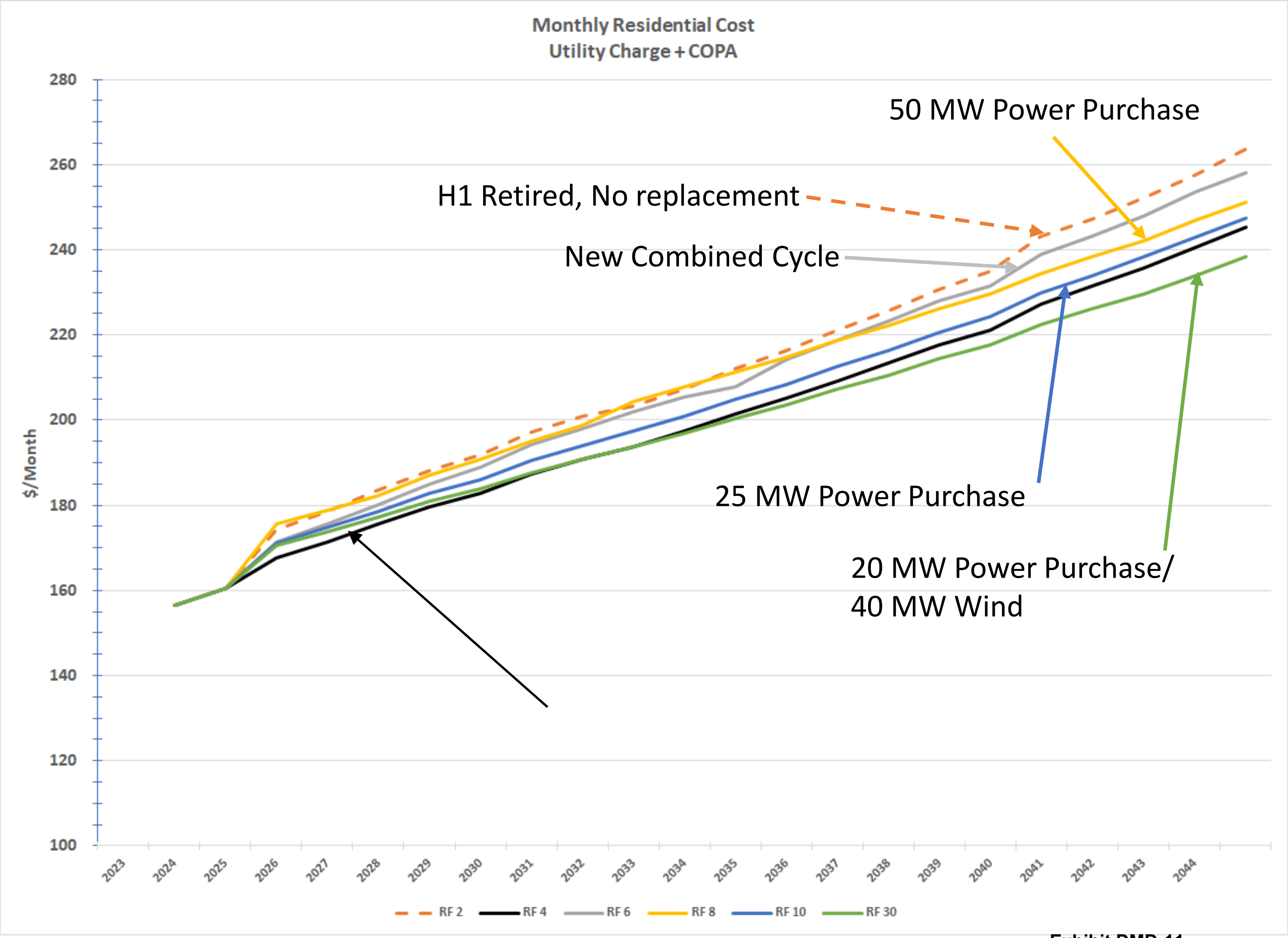


Emissions (10^6 tons)	
RF 2	20.9
RF 4	22.9
RF 6	20.0
RF 10	19.3
RF 8	17.5

Healy 1 Retirement

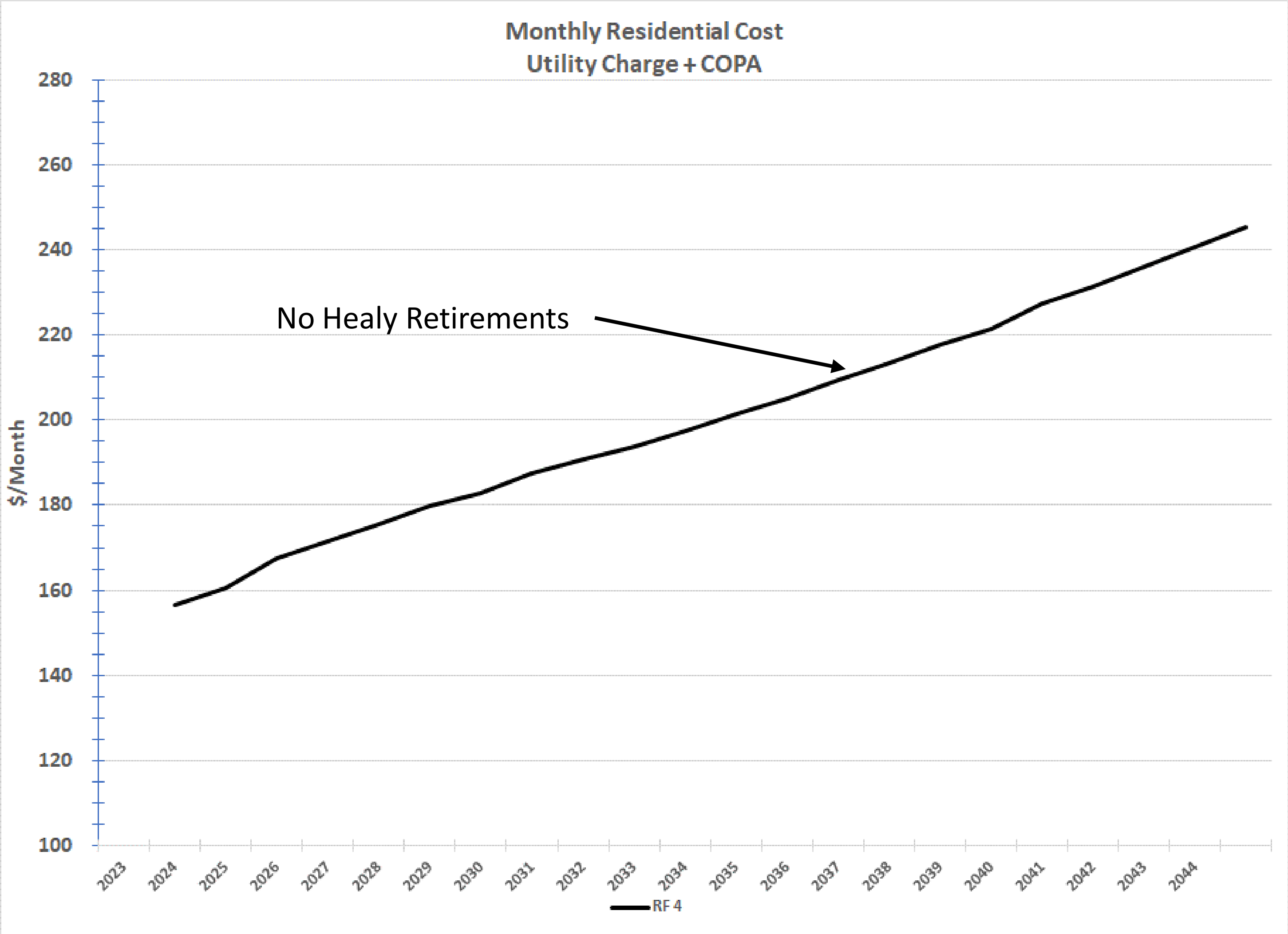
- Retirement with no replacement power adds significant costs to system
- New combined cycle higher than no retirement
- With just replacement power from south, a smaller purchase amount results in lower cost of power – difficult to fit 50 MW in with loss of only 25 MW (Healy 1)
- Replacement power commensurate with loss of Healy 1 and wind is most economic of scenarios options investigated
- Wind scenario includes the capital and operating costs of a BESS sufficient in capacity (MW) and energy (MWh) to regulate the wind resource

Emissions (10^6 tons)	
RF 2	20.9
RF 4	22.9
RF 6	20.0
RF 10	19.3
RF 8	17.5
RF 30	17.8



- Initial analyses investigated whether to implement the SCR on Healy 1
  - Should Healy 1 be retired?
- But, all options should be on the table
- What about retirement of other GVEA resources?
  - North Pole 1 and 2 and Zehnder units expensive to operate but are there only to fill in the peaks
  - North Pole Combined Cycle is very efficient, can fluctuate with load, and can provide regulation for Eva Creek
- Would retiring Healy 2 provide benefits to GVEA?

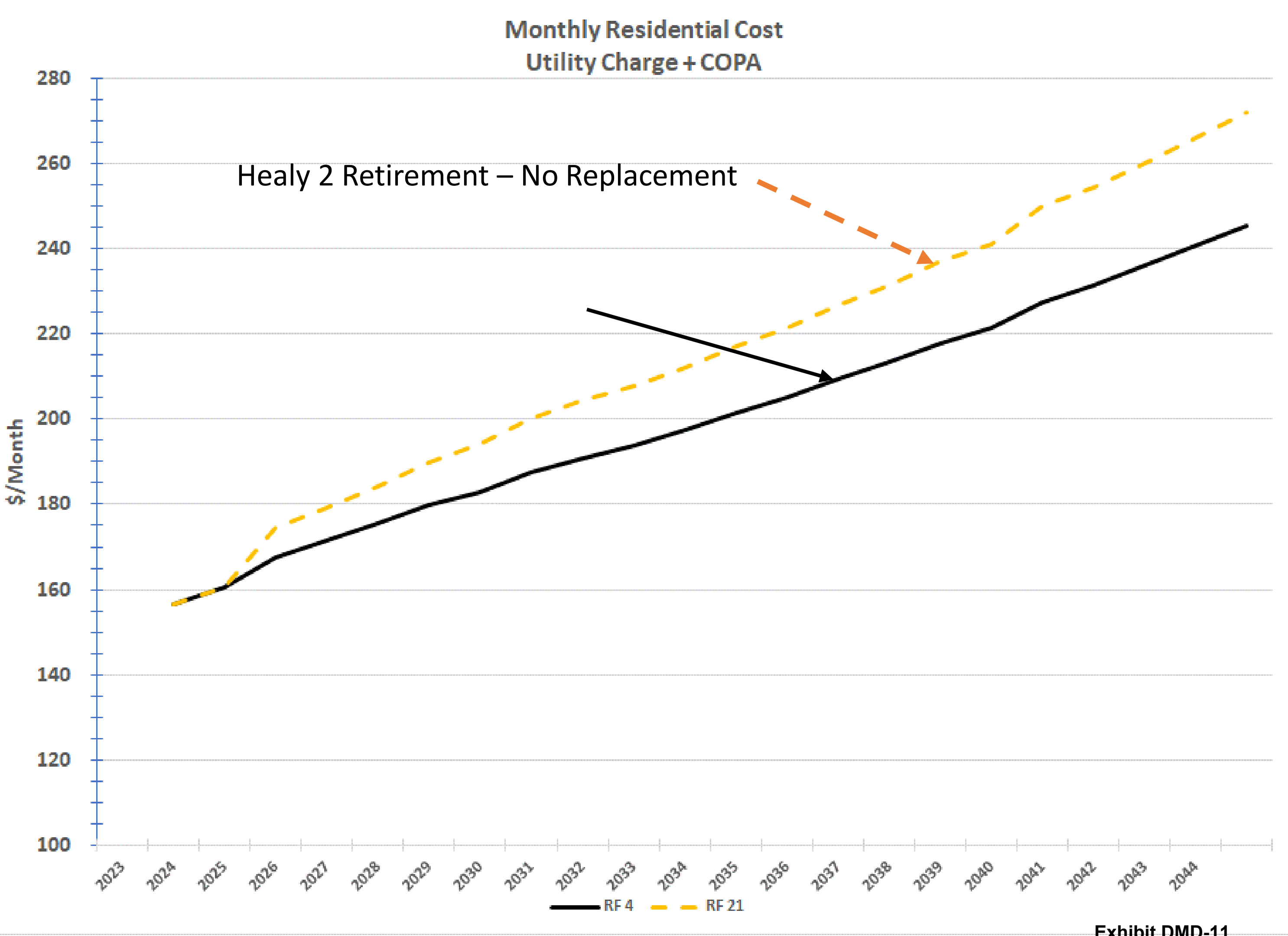
What if Healy 2 was retired instead of Healy 1?



Emissions (10^6 tons)	
RF 4	22.9

What if Healy 2 was retired instead of Healy 1?

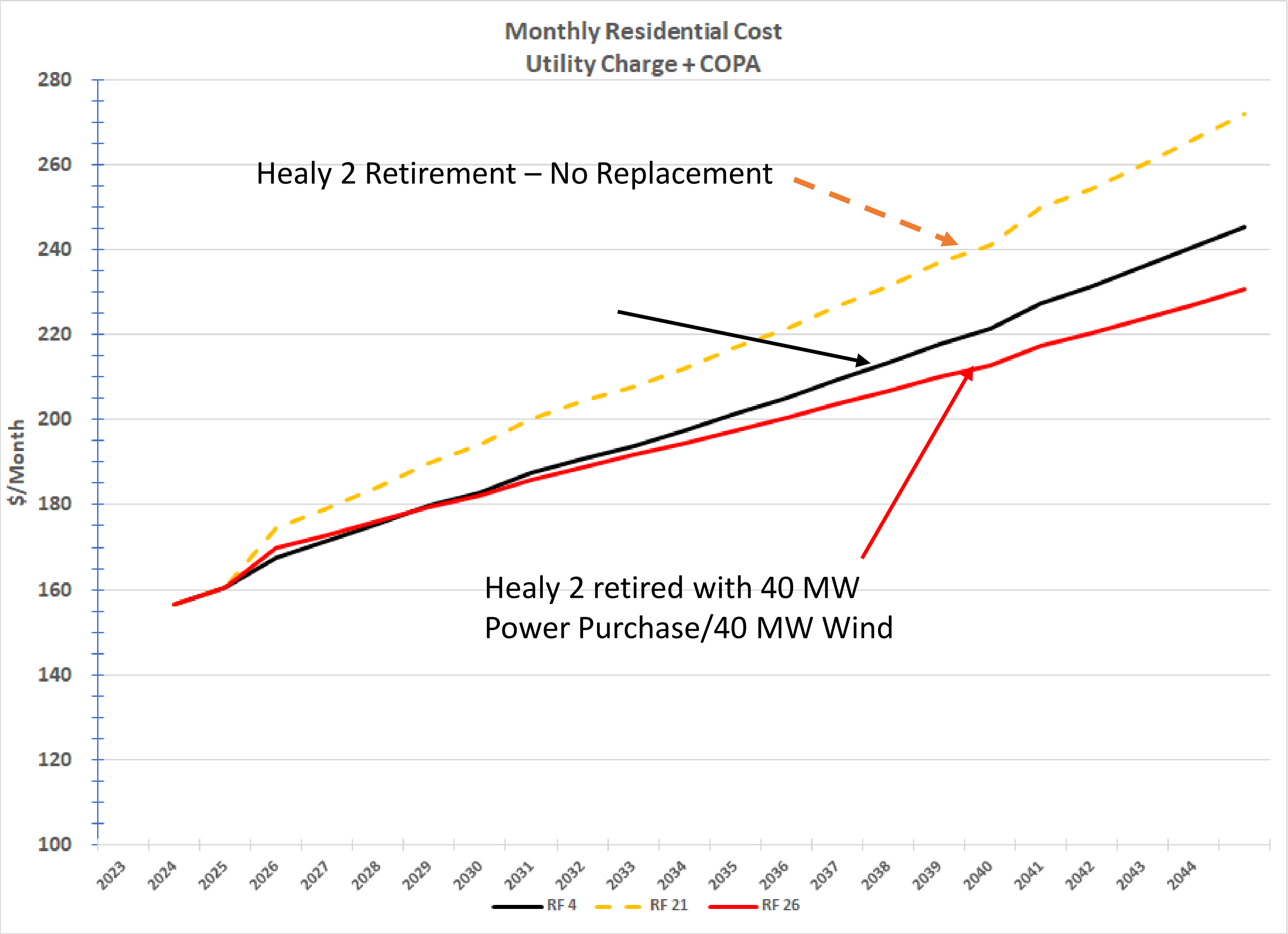
- With no replacement power, retirement of Healy 2 results in very high cost of power



Emissions (10^6 tons)	
RF 4	22.9
RF 21	18.3

What if Healy 2 was retired instead of Healy 1?

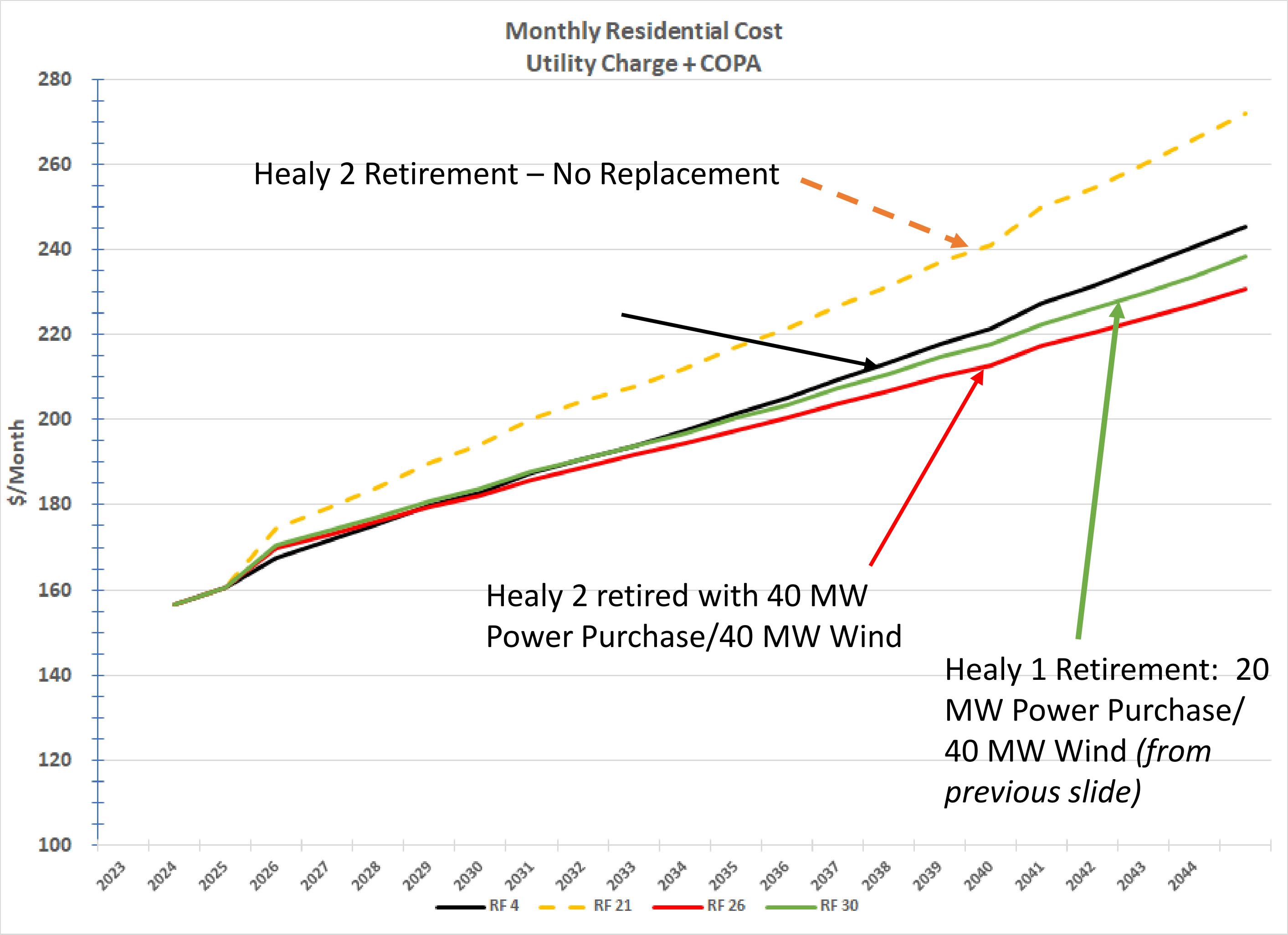
- With no replacement power, retirement of Healy 2 results in very high cost of power



Emissions (10^6 tons)	
RF 4	22.9
RF 21	18.3
RF 26	15.1

What if Healy 2 was retired instead of Healy 1?

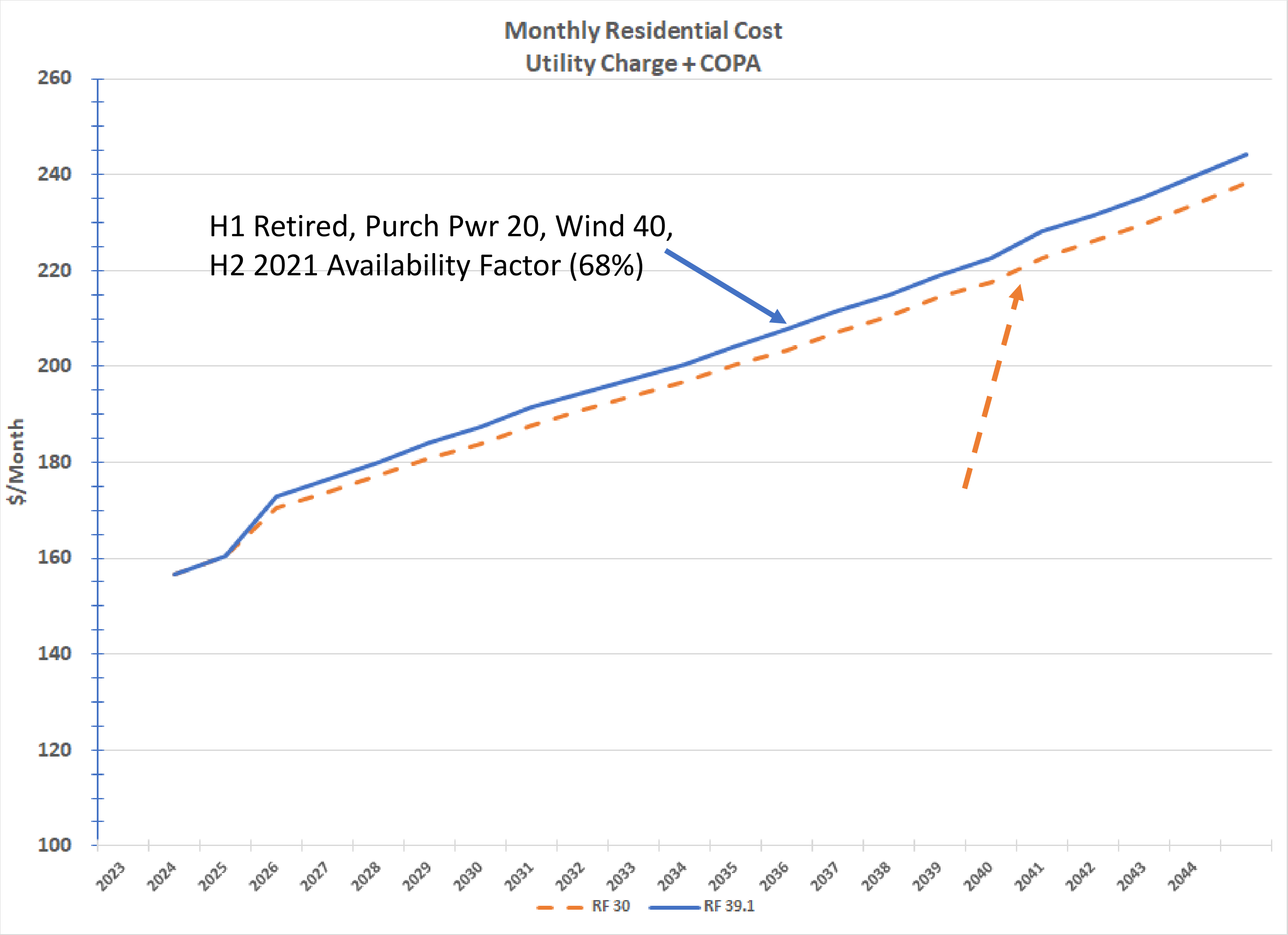
- With no replacement power, retirement of Healy 2 results in very high cost of power
- Retirement of Healy 2 instead of Healy 1 results in lower costs



Emissions (10^6 tons)	
RF 4	22.9
RF 21	18.3
RF 26	15.1
RF 30	17.8

Healy 2 Availability

- Maintaining Healy 2 in operating fleet and retiring Healy 1 is based on capital expenditures to Healy 2 improving Availability Factor to approximately 88%
- Even with this high availability factor, retirement of Healy 2 is favored
- If expenditures do not work and Healy 2 has a lower availability factor, retirement of Healy 2 instead of Healy 1 is favored even more

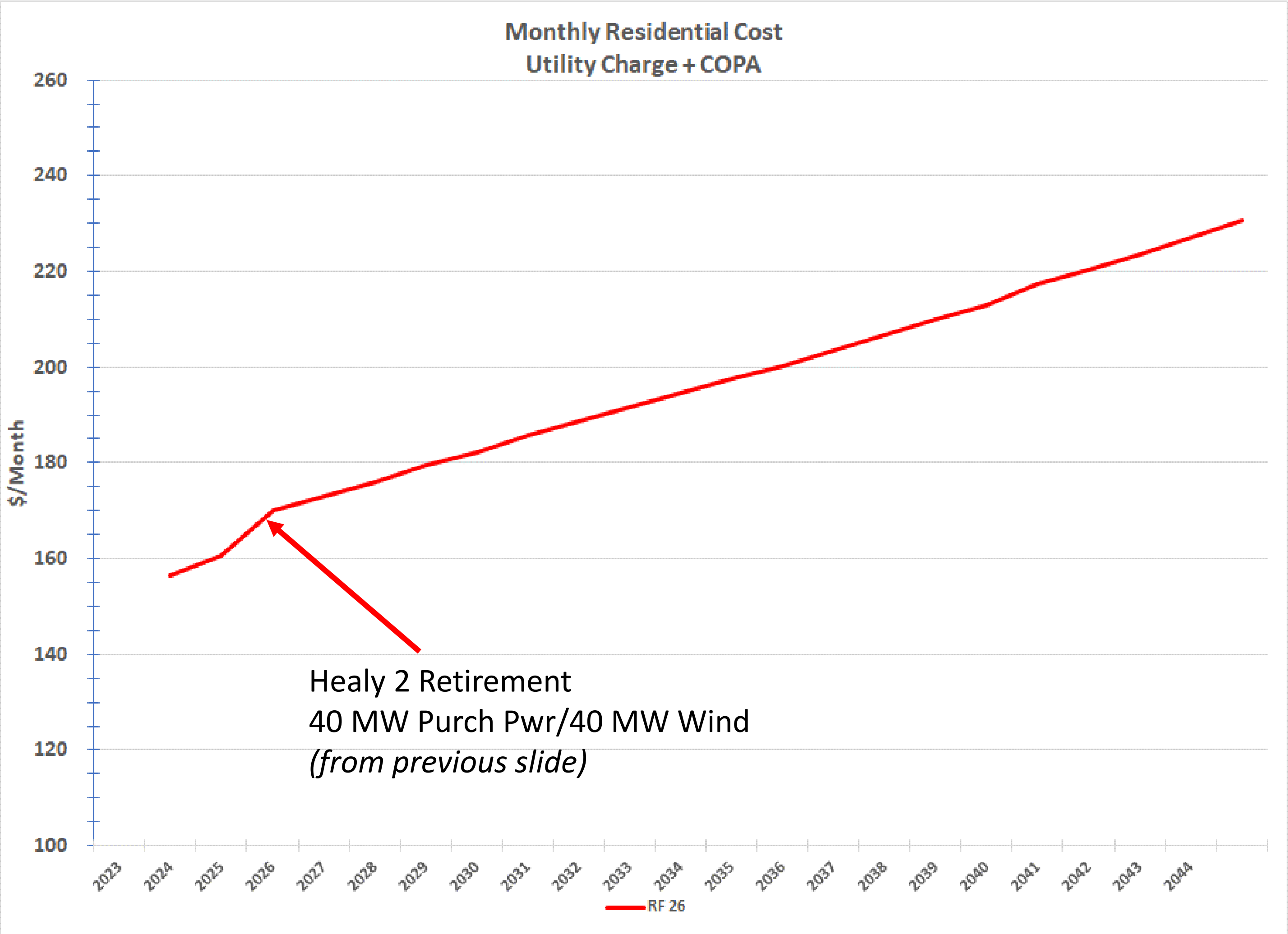


Can both Healy units be retired?

- Retiring both units leads to much higher costs without firm replacement power

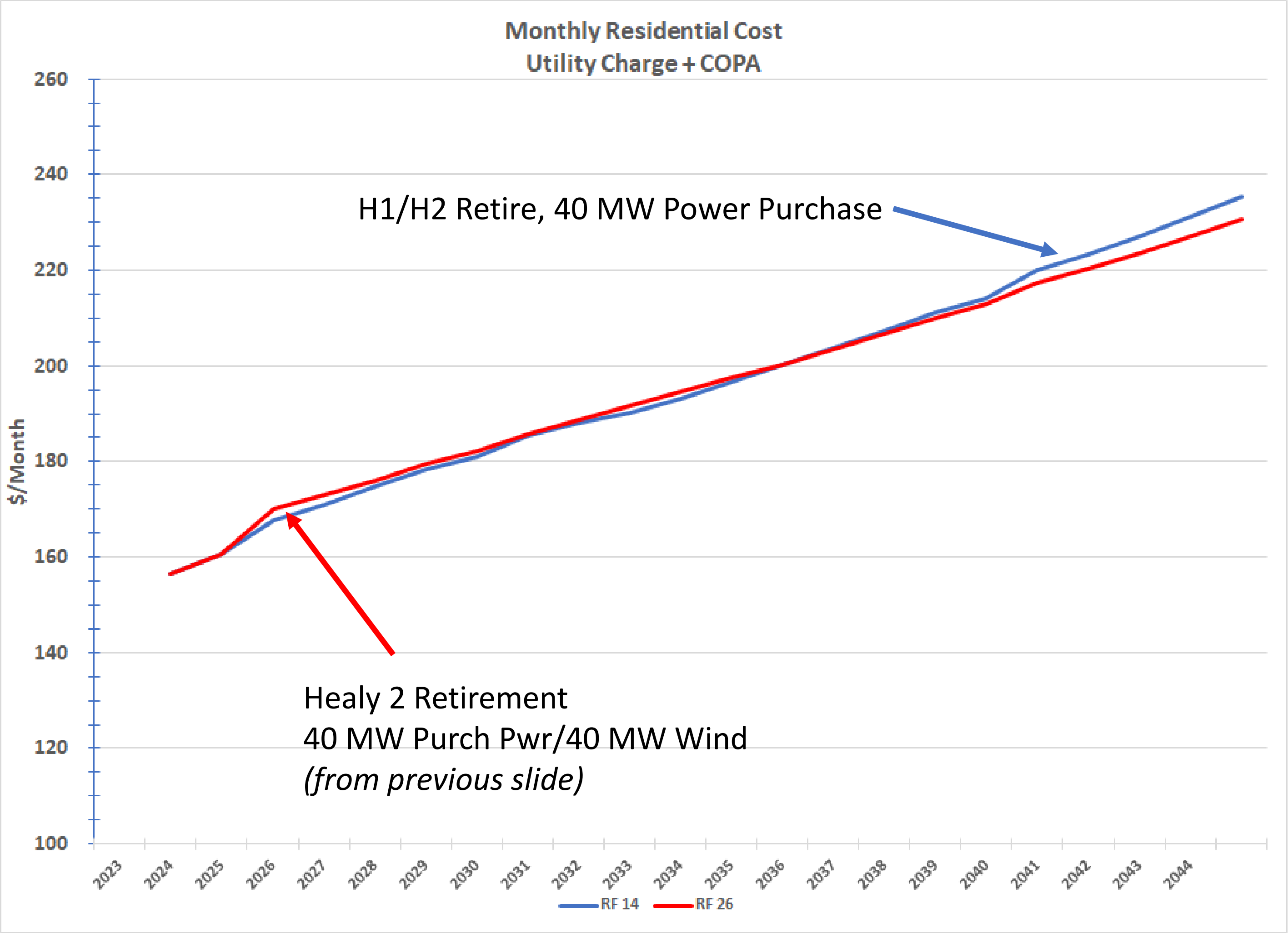
Emissions (10^6 tons)

RF 26 **15.1**



Can both Healy units be retired?

- Retiring both units leads to much higher costs without firm replacement power
- Wind might further lower costs but needs to fit in with power purchase

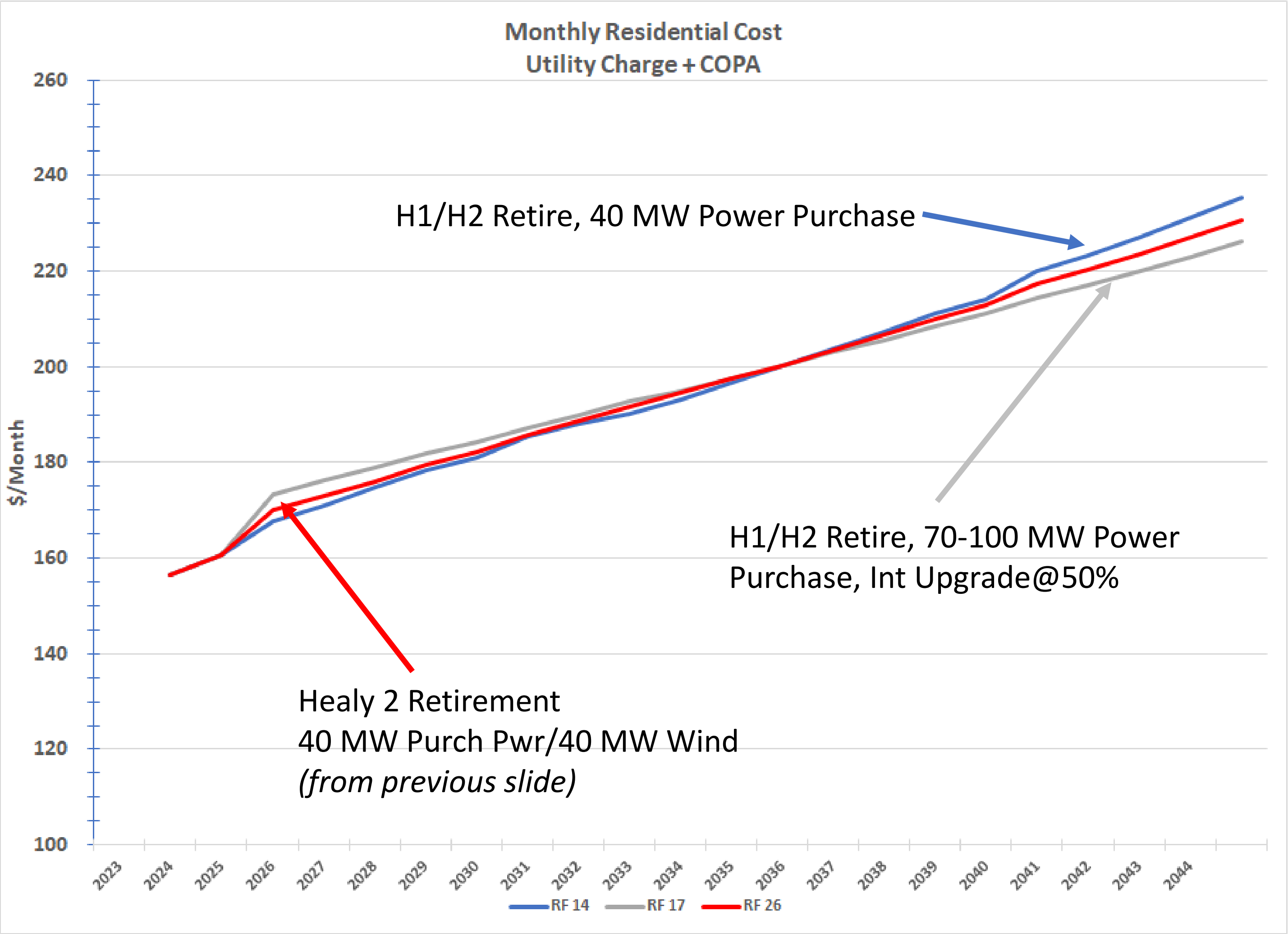


Emissions (10^6 tons)	
RF 26	15.1
RF 14	12.8

Can both Healy units be retired?

- Retiring both units leads to much higher costs without firm replacement power
- Wind might further lower costs but needs to fit in with power purchase
- Can lower costs from retiring Healy 2 only, but only small amount
  - Requires intertie upgrade for replacement power
  - Can upgrade be accomplished in 2 ½ years?
- Retirement of both Healy units further reduces fuel diversity

Emissions (10^6 tons)	
RF 26	15.1
RF 14	12.8
RF 17	12.7



Summary

- Analysis performed over the past several months indicates that the retirement of a Healy unit can lead to lower costs if sufficient replacement power is available
- Of the two Healy units, it is more economic to retire Healy 2
- Retirement of both Healy units right away provides only a small long-term gain over retiring Healy 2 while imposing certain risk factors
  - Sufficient replacement power from the southern utilities requires the upgrade of the Anchorage – Healy intertie
  - Can this upgrade be accomplished before the Healy units are retired (2 ½ years)?
  - Increases reliance on oil-fired generation during times of intertie outages

Summary *(continued)*

- Adding wind resources to the system can provide both economic and environmental benefits if:
  - Prices are within the range assumed
  - A BESS of sufficient size (capacity and energy) is added to the system for regulation
  - Minimum focusing on a 46 MW / 184 MWh system
  - Should be capable of expansion
- All scenarios run with wind included the capital and operating costs of a BESS

Going Forward

- Continue operation of Healy 1 (implement SCR on Healy 1)
- Initiate steps to retire Healy 2
  - Work with RCA regarding retirement of Healy 2
- Secure firm power replacement / gas commensurate in size with lost power
- Wind
  - Secure wind resource of approximately 40 MW
  - Investigate possibilities to implement interruptible loads (heat/thermal storage, etc.) that could increase the amount of wind that could be accommodated into they system
  - Investigate wind forecasting models
- Install a BESS commensurate in size (MW and MWh) with wind and need to regulate
  - Interruptible loads would reduce need for Regulation Down

GOLDEN VALLEY ELECTRIC ASSOCIATION, INC'S RESPONSE TO THE REGULATORY COMMISSION OF ALASKA'S ORDER U-22-029(3)

ATTACHMENT C

CONFIDENTIAL PURSUANT TO CONFIDENTIAL ORDER U-22-029(2)

This Excel model, titled "Hubbard Dispatch Evaluation Model" is Confidential and will be filed with the parties under separate seal.

Golden Valley Electric Association
PO Box 71249, Fairbanks, AK 99707-1249 • (907) 452-1151 • www.gvea.com
Your Touchstone Energy® Cooperative

December 14, 2022

Mr. Arthur W. Miller
Chief Executive Officer
Chugach Electric Association, Inc.
5601 Electron Drive
Anchorage, Alaska 99519 – 6300

Sent Electronically Via: Arthur_Miller@chugachelectric.com

Re: Amendment to Memorandum of Understanding

Dear Mr. Miller:

This document serves as a response to the letter agreement transmitted on November 21st and is a follow-up to our discussion the morning of November 29th. Consistent with that discussion, Golden Valley Electric Association, Inc. (GVEA) submits this counter to the letter agreement (Amendment) that amends the Memorandum of Understanding (MOU) between GVEA and Chugach Electric Association, Inc. (Chugach). Under Section 3(e) of the MOU, GVEA has the ability to provide its own fuel to meet its commitment with Chugach to purchase 120,000 MWh of economy energy, and GVEA is exercising that option through this Amendment.

I. Amendments to MOU

a. Section 3(e) is amended as follows:

i. The first paragraph is modified to state "Chugach will sell and GVEA will purchase a minimum of 120,000 MWh of economy energy from Chugach for each 12-month period from the date the conditions contained in Section 3.a of this MOU are satisfied until expiration of the two-year term in the Special Contract and Service Agreement for Gas Sales Service between GVEA and ENSTAR Natural Gas Company (ENSTAR), dated November 30, 2022 (ENSTAR Agreement). Modifications or extensions of the ENSTAR Agreement's two-year term shall not extend the term of this MOU absent Chugach's written agreement to such an extension.

ii. After the last paragraph, the following new paragraphs are inserted:

1. Subject to the terms and conditions of the ENSTAR Agreement, GVEA will supply Chugach with 1,000,000 Mcf (1 Bcf) of natural gas (Gas) during each of the two 12-month periods that the

ENSTAR Agreement is effective at the "Daily Contract Quantity" delivery rates set out therein.

2. Chugach shall take delivery of the Gas at the Beluga Pipeline Company Connection (ENSTAR/APC station B605, Meters 700 & 701, BPLC Nos. 8101 & 8102) (Delivery Point) and transport the Gas from the Delivery Point to Chugach's generation facilities.

3. GVEA shall reimburse Chugach for the tariffed cost of transporting the Gas from the Delivery Point to Chugach's generation facilities.

4. For purposes of economy energy sales under this MOU, Chugach will manage the daily nomination, dispatch, tracking, and reporting of the Gas (Services) in a manner consistent with the following:

    a. Chugach shall not be obligated to take delivery of the Gas in situations where, despite Chugach's good faith efforts, Chugach is unable to use the Gas to produce economy energy for GVEA under this MOU. It is the Parties' intent and understanding that such a situation would qualify as a "Customer Excused Event" under the ENSTAR Agreement.

    b. GVEA shall cooperate in good faith to timely provide information and assistance to Chugach as necessary for Chugach to effectively and efficiently perform the Services. GVEA shall keep Chugach apprised of all communications with ENSTAR that would impact Chugach's performance of the Services, including, but not limited to, any notifications regarding a "Company Excused Interruption", "Company Force Majeure Event", "Customer Excused Event", or "Customer Force Majeure Event", as those terms are defined in the ENSTAR Agreement (collectively, Interruption Events).

    c. GVEA authorizes and grants to Chugach all authority necessary or useful to Chugach, including the authority to act as GVEA's agent under the ENSTAR Agreement, with respect to Chugach's performance of the Services.

    d. Chugach will provide GVEA and ENSTAR with as much advance notice as reasonably possible any time Chugach is unable to use the Gas to produce economy energy for GVEA. For the sake of clarity, however, Chugach shall have no responsibility, obligation, or liability for notifying ENSTAR of Interruption Events under the ENSTAR Agreement. Chugach shall coordinate in good faith with GVEA and ENSTAR regarding the rescheduling of any undelivered Gas associated with an Interruption Event.

5. In no event shall either party or any of its representatives be liable under this MOU to the other party for indirect, incidental, special, exemplary, punitive or enhanced damages, lost profits or revenues arising out of, relating to, or in connection with any breach of this MOU.

Except as expressly provided in this letter, all terms and provisions of the MOU are unchanged and remain in full force and effect.

If you find the above acceptable and reflects our understanding, please sign and return a copy to me.

Sincerely,

John J. Burns
President & Chief Executive Officer

Agreed to and Accepted:

Arthur W. Miller
Arthur W. Miller
Chief Executive Officer; Chugach Electric Association, Inc.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: Robert M. Pickett, Chairman
Stephen McAlpine
Antony G. Scott
Daniel A. Sullivan
Janis W. Wilson

In the Matter of the Revenue Requirement Revisions Designated as TA101-118 and TA140-97 and the Cost-of-Energy Adjustment Revisions Designated as TA102-118, TA105-118, TA106-118, TA108-118, TA109-118, TA111-118, TA141-97, TA144-97, TA145-97, TA147-97, TA148-97, and TA150-97 for Water Public Utility Service Filed by GOLDEN HEART UTILITIES, INC. and COLLEGE UTILITIES CORPORATION	U-19-070 ORDER NO. 21
In the Matter of the Revenue Requirement Revisions Designated as TA95-290 and TA145-37 and the Cost-of-Energy Adjustment Revisions Designated as TA96-290, TA99-290, TA100-290, TA102-290, TA103-290, TA105-290, TA146-37, TA149-37, TA150-37, TA152-37, TA153-37, and TA155-37 for Wastewater Public Utility Service Filed by GOLDEN HEART UTILITIES, INC. and COLLEGE UTILITIES CORPORATION	U-19-071 ORDER NO. 21
In the Matter of the Cost-of-Service and Rate Design Studies Designated as Tariff Revisions TA103-118 and TA142-97 for Water Public Utility Service Filed by GOLDEN HEART UTILITIES, INC. and COLLEGE UTILITIES CORPORATION	U-19-087 ORDER NO. 18
In the Matter of the Cost-of-Service and Rate Design Studies Designated as Tariff Revisions TA97-290 and TA147-37 for Wastewater Public Utility Service Filed by GOLDEN HEART UTILITIES, INC. and COLLEGE UTILITIES CORPORATION	U-19-088 ORDER NO. 18

ORDER RESOLVING REVENUE REQUIREMENT AND COST-OF-SERVICE ISSUES, REQUIRING FILINGS, AND ALLOWING COMMENT

BY THE COMMISSION:

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Regulatory Commission of Alaska
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Overhead Transfer

GHU and CUC propose an $806,557 adjustment to their 2018 test year overhead transfer expense because it was abnormally large due to the number of capital projects in the test year. GHU and CUC use in-house labor for both capital and operations and maintenance (O&M) projects. When an employee spends time on O&M projects, the costs are booked to the appropriate O&M account as expense. When an employee works on a capital project, the costs are directly booked to the capital project, instead of as an expense. GHU and CUC state that the cost of the employee's associated benefits ("overhead") are first recorded as an expense but then, at the end of the year, "transferred" to the capital project. GHU and CUC summarize that all capitalized labor costs are ultimately reflected in plant in service and are not included in O&M expense.[87]

GHU and CUC state that CUC placed in service a significantly greater amount of water plant during the 2018 test year. As a result, a disproportionate amount of overhead transfers occurred during this period. GHU and CUC assert the pro forma adjustment normalizes CUC water overhead transfers to reflect a 5-year (2014-2018) average. This adjustment results in an increase to expenses of $806,557 in the final revenue requirement.[88]

RAPA argues that GHU and CUC's proposed adjustment to overhead transfer is not adequately justified as unusual or nonrecurring and is one-sided. RAPA asserts the adjustment allows the same expense to be included in operating expenses, in rate base, and (in minor part) depreciation expense. RAPA asserts that by reducing the transfer, GHU and CUC increase the net amount of administrative expense remaining in the revenue requirement, but it does not remove the corresponding overhead

[87] GHU and CUC Closing at 43; *See* Tr. 445-449, 502-504.

[88] GHU and CUC Closing at 43.

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transferred from test year plant and from depreciation. RAPA asserts that if the proposed adjustment is allowed, GHU and CUC will recover an additional $806,557 in operating expenses, earn a return on the 13-month average of that amount, and recover depreciation expense on the total.[89]

Wilkes stated that the proposed adjustment reflects that CUC will not be undertaking capital projects in near future and seeks to recover what will be its normal operating expenses. He states that it used a multiyear average to arrive at a conservative normalized level that is expected to be incurred during the period that new rates are in effect; he believes that a five-year average best establishes a representative figure. Wilkes explained that denying the adjustment would mean that GHU and CUC will not receive an appropriate allowance for the normal operating expenses of running the utility. Wilkes further explained that there is no dispute that the GHU and CUC's capital projects are in service and used and useful, so it is not appropriate to remove the amount from rate base.[90]

Both parties cite to Order U-16-066(19) in support of their argument. There we found:

> Our regulations allow adjustments to the test year for known and measurable changes or to delete or average unusual or nonrecurring events. The averaging proposed by ENSTAR is not known and measurable. And legal and outside services are not unusual or nonrecurring events that may be averaged.[91]

While we generally discourage using averages, it can be appropriate in some circumstances. In Order U-18-043(15), we denied Cook Inlet Natural Gas Storage

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[89]RAPA Closing at 18-20; T-13 (Fairchild-Hamilton) at 29-32.

[90]T-9 (Wilks Reply) at 23.

[91]Order U-16-066(19) at 88. ENSTAR Natural Gas Company, a Division of SEMCO Energy, Inc. (ENSTAR).

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Alaska, LLC (CINGSA) a pro forma adjustment to its legal expenses.[92] CINGSA used the cost of a single proceeding regarding litigation over a portion of 14 billion cubic feet of natural gas found when drilling wells as representative and predictive of its future costs. We denied the adjustment but allowed the possibility for such adjustments in rate cases:

> In principle, CINGSA could have made a persuasive argument in favor of an allowance for non-rate case legal expenses through a normalizing adjustment to operating expenses. For example, CINGSA could have cited the average of several years of necessary, valid expenses.[93]

In these dockets the use of a normalizing average is appropriate. The amount of capital projects and related overhead transfers in the previous four years are relatively similar and substantially lower than in the 2018 test year. GHU and CUC supported their adjustment with the actual 5-year average of overhead transfer expenses and testimony regarding its relative lack of future capital projects.

We find that the size of the overhead transfer was clearly anomalous and quite large relative to the overall revenue requirement. We find that GHU and CUC supported the proposed use of an average for its overhead transfer expense. We allow GHU and CUC's proposed overhead transfer pro forma adjustment using a 5-year average.

Insurance

GHU and CUC propose a pro forma adjustment reflecting a $4,692 decrease in insurance expense to reflect a 5-year average. GHU and CUC assert that actual damage costs not covered by insurance will fluctuate each year depending on weather conditions, snow cover, depth of freezing, length of winter, and other factors.[94]

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[92]Order U-18-043(15), *Order Resolving Revenue Requirement and Cost-Of-Service Issues and Requiring Filings*, filed August 16, 2019 (Order U-18-043(15))

[93]Order U-18-043(15) at 16.

[94]H-001 (TA101-118), Exhibit B at 42 (7k).

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Memorandum

To: 2023 ENSTAR Natural Gas Rate Case Tax Files

From: Marc Caillouet, Partner Houston

Date: May 19, 2023

Subject: Cost of Removal Memorandum

INTRODUCTION

The purpose of this memorandum is to document the law and regulations applicable to removal costs under a tax normalization method of accounting for ENSTAR Natural Gas Company ("ENSTAR") and Alaska Pipeline Company ("APC").

ENSTAR is a regulated public utility that delivers natural gas to more than 150,000 residential, commercial, and industrial customers in and around the Anchorage and Cook Inlet area in Alaska. ENSTAR's service area encompasses over 57% of the population of Alaska.

PwC was engaged by ENSTAR to compute the accumulated deferred income taxes and excess deferred income taxes associated with removal costs as of December 31, 2017 for both ENSTAR and APC.

BOOK ACCOUNTING FOR COST OF REMOVAL

Because of the importance of the rate base in the determination of the revenue requirement, the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USoA") contains detailed instructions and definitions concerning the capitalization of property, plant and equipment. Virtually all costs incurred to get an asset ready for service are capitalized and depreciated. This is significant because when costs benefit customers over an extended period, generally such costs should be capitalized as property, plant and equipment and recovered through depreciation charges on a straight-line basis over the estimated life of the asset, as opposed to permitting recovery of that cost as a period cost. The depreciation charge each year is calculated by applying a depreciation rate to the capitalized property, plant and equipment balance. The depreciation rate is determined by simply converting the useful life in years to a percentage. A 10-year life asset converts to a depreciation rate of 10 percent (i.e., 1 year / 10 years = 10%). An asset with a 25-year life converts to a depreciation rate of 4 percent (i.e., 1 year / 25 years = 4%).

The concept of intergenerational equity is embodied in depreciation charges — the ratepayer who is using/benefitting from the asset is asked to pay for the service being provided. The FERC USoA provides for this concept by setting out a significant list of construction activities to be capitalized and recovered through depreciation charges.

The FERC USoA also provides guidance on accounting for removal costs ("cost of removal"). Cost of removal is the cost incurred to remove, dispose, or otherwise permanently retire an asset from service at the end of its life. It reduces (is a debit to) FERC Account 108 – Provision for Depreciation when incurred.

FERC defines cost of removal as "the cost of demolishing, dismantling, tearing down, or otherwise removing retirements of utility plant, including the cost of transportation, and handling incidental thereto." Cost of removal typically consists of all the costs incurred in connection with the retirement of plant. In some instances, the property is physically removed, cleaned, reconditioned, and moved to a storeroom or storage yard, or relocated to operate in another location.

Cost of removal is distinguished from salvage. Salvage represents amounts received from selling removed/retired assets. For regulated entities, the cost of removal is almost always greater than realized salvage proceeds. Many utilities accrue for the estimated "Net salvage costs", "Negative cost of removal" or "Cost of removal" over an asset's useful life through an additional positive or negative factor included in annual depreciation expense. In this manner, the customer who is using/benefitting from the service provided by that property, plant and equipment will pay the costs of such property, plant and equipment over its estimated useful life. Payments include both the initial cost of the asset and estimated salvage/cost of removal that will be incurred upon retirement. Under this approach, depreciation charges are accumulated and charged (credited) to the balance sheet FERC Account 108 and this account is debited for removal costs when actually incurred. Until removal costs are incurred, the customer has effectively prepaid for the cost of removal and, in rate cases, the "credit" in Accumulated Depreciation reduces rate base.

The importance is that the book depreciation "rate" includes both a factor to allocate/recover the book cost over the estimated life, but also includes a factor to recover the estimated cost of removal over that period as well.

INCOME TAX ACCOUNTING FOR COST OF REMOVAL

For income tax purposes, property, plant and equipment is also capitalized and depreciated. However, compared to book/regulatory accounting, certain amounts capitalized for books are permitted to be currently deducted for income tax purposes. These are referred to as basis differences. Further, tax depreciation will likely differ from book depreciation. Whereas book depreciation seeks to allocate the cost of an asset over the estimated life of the asset on a straight-line basis, for income tax purposes, tax depreciation is generally accelerated and uses shorter lives.

The current tax depreciation method is the Modified Accelerated Cost Recovery System ("MACRS"). Over the lives of the assets, book depreciation will equal tax depreciation, with tax depreciation generally exceeding book depreciation in the early years and book depreciation exceeding tax depreciation in the later years.

For income tax purposes, cost of removal/salvage are deductible/includable in taxable income when incurred, creating a timing difference. However, for book accounting purposes, cost of removal/salvage amounts are "built up" through including a cost of removal/salvage factor in depreciation rates as such amounts are recorded each year which reverse in the year the cost of removal/salvage is incurred/recovered.

DEPRECIATION STUDY

Regulated utilities typically utilize the group depreciation concept. Under this concept, similar assets within groups are all assigned a similar life. Depreciation studies are performed that track assets from when they are placed in service until when they are retired. By studying different vintages of assets in this manner, actuarial data is developed that is useful in determining the remaining lives of assets remaining in service.

The depreciation study will also identify the cost of removal/salvage component to include in developing the appropriate depreciation rate. Again, actual experience with costs of removing/obtaining salvage are used to consider how much needs to be accrued each year to build up the eventual cost of removal/net salvage at the time of retirement.

REGULATORY ASSETS & LIABILITIES

The ratemaking process permits regulated entities to recover costs that enterprises in general would charge to expense. In situations where this occurs, capitalization of such costs as a "regulatory asset" is appropriate under ASC 980, Regulated Operations ("ASC 980"). The typical example given relates to storm costs. In cases where a regulated utility incurs costs to recover from a storm (hurricane, tornado) many of such costs would typically be expensed under book accounting. However, in the ratemaking process, it is not unusual for the regulator to permit the utility to capitalize such costs and permit recovery over an agreed-upon period (typically, 5 or 10 years). In such cases, the utility will capitalize the costs to FERC USoA 182.3 and amortize the costs to expense as the increased revenues/tariffs are being recovered.

The guidance for account 182.3 follows:

"182.3 Other regulatory assets

A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (See Definition No. 30.)

B. The amounts included in this account are to be established by those charges which would have been included in net income, or accumulated other comprehensive income, determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing rates that the utility is authorized to charge for its utility services. When specific identification of the particular source of a regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, account 407.4, regulatory credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of account 407.4 shall be charged to account 407.3, regulatory debits, concurrent with the recovery in rates.

C. If rate recovery of all or part of an amount included in this account is disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, or Account 435, Extraordinary Deductions, in the year of the disallowance.

D. The records supporting the entries to this account shall be kept so that the utility can furnish full information as to the nature and amount of each regulatory asset included in this account, including justification for inclusion of such amounts in this account."

PwC's Utilities and Power Companies guide (18.2) discusses costs that would typically be expensed but may be capitalized by a regulated utility if the costs are probable of recovery through future rates.

Examples of regulatory assets include:

- One-time legal settlement costs
- Fuel costs subject to recovery under an Energy Adjustment Clause
- Recovery of early retired assets
- Non-service related pension costs capitalized (not capitalized for enterprises in general)

Regulatory liabilities exist as well, for costs permitted in the ratemaking process before such costs are recognized for GAAP. Examples of regulatory liabilities include:

- Cost of removal of PPE assets recognized through depreciation charges
- Changes in income tax rates (such as when the Federal Income Tax rate was reduced under TCJA)
- Fuel costs subject to refund under and Energy Adjustment Clause

As mentioned above, regulated utilities typically include a factor for net cost of removal in depreciation rates.

DEFERRED TAX ACCOUNTING

The above discussion of accounting for property, plant and equipment, depreciation and cost of removal/salvage gives rise to different book and tax treatment of each. Deferred income taxes are required on book-tax differences. For regulated utilities, the Internal Revenue Code ("IRC") contains certain sections requiring the treatment that must be utilized by utilities and regulators in the ratemaking process. These sections relate primarily to book versus tax depreciation differences. The purpose of these requirements ("normalization rules") is to prevent regulators from flowing the acceleration of tax depreciation to current ratepayers, thwarting the intent of Congress when accelerated depreciation was added to the IRC.

Under the normalization rules, utilities must reflect the income tax consequences as if the book depreciation amount were used for income tax purposes with the difference between that amount and actual tax depreciation recorded as Accumulated Deferred Income Tax ("ADIT") and used to reduce rate base or included as zero cost capital in determining the rate of return. In this manner, utilities enjoy the same benefits of accelerated depreciation as other entities. The depreciation book-tax difference is referred to as a "protected" difference in that ADIT must be recorded. That difference is protected by the IRC. If a regulator chooses not to permit deferred taxes on the depreciation book-tax difference, the utility is no longer eligible to claim accelerated depreciation. Other book-tax differences (not related to depreciation) are considered unprotected and whether ADIT are recorded or flowed through to ratepayers is at the discretion of the utility/regulator.

Cost of Removal / Salvage and ADIT

There is also a book-tax difference related to cost of removal/salvage. Amounts are recorded for books ahead of the eventual tax deduction resulting in ADIT. The IRS recently provided guidance on the protected/unprotected status of these items. In Rev Proc 2020-39 (and several recent PLR's), the IRS clarified that cost of removal is not a protected book-tax difference since the income tax deduction for removal cost is not referenced to a depreciation section of the code. The implications of this clarification are reflected in, among other things, the reversal of protected excess ADIT.

When income tax rates change, ADIT existing at the time of the rate change are remeasured with the difference between the ADIT accumulated at the prior tax rate and the ADIT that would have been recorded if the newly enacted income tax rate had been in existence from Day 1 recorded as a regulatory liability (if the newly enacted income tax rate is less than the previous rate). To comply with the normalization rules for changes in income tax rate, the excess ADIT should be used to reduce customer rates no more rapidly than under the Average Rate Assumption Method ("ARAM") or, if records are unavailable to compute ARAM an alternative calculation, the Reverse South Georgia Method ("RSGM") is permitted to return the excess ADIT to ratepayers. Under either ARAM or RSGM, the calculation returns the excess ADIT over the book lives of the property, plant and equipment used to derive the protected ADIT balance in the first place.

The importance with either ARAM or RSGM and the IRC's determination that cost of removal is unprotected is that the portion of the book depreciation rate representing cost of removal must be stripped out of the depreciation rate determination so that only the portion of the depreciation rate representing the property, plant and equipment lives is to be used for the reversal under ARAM or RSGM. If the excess ADIT is reversed using the depreciation rate including a cost of removal factor, that would produce a reversal more rapid than over the lives as required under the normalization requirements of the IRC.

APPLICATION TO ENSTAR

ENSTAR had a cumulative gross deferred tax liability at December 31, 2017 totaling $46,041,572 inclusive of a $74,264,715 gross deferred tax liability associated with "Federal Fixed Assets". The "Federal Fixed Assets" temporary difference primarily includes differences between book accounting depreciation methods and depreciable lives compared to Federal income tax depreciation methods and depreciable lives. These depreciation method and life differences are "protected" temporary differences, however, the $74,264,715 also includes cumulative temporary differences associated with removal costs which are "unprotected" by the normalization rules.

PwC was engaged to determine the amount of the gross deferred balance related to removal costs for ENSTAR, exclusive of APC, and the related excess deferred tax resulting from the tax rate change in 2017. ENSTAR provided the depreciation study from 2007 and a subsidiary ledger schedule which identified the accumulated depreciation related to removal costs as of December 31, 2007. ENSTAR also provided a schedule detailing the book depreciation expense related to removal costs; the actual removal costs; and the actual salvage in each subsequent year.

As part of the analysis, PwC first estimated the amount of the removal costs in the depreciation accrual for removal costs which included both ENSTAR and Alaska Pipeline Company ("APC") operations. To calculate this amount, PwC used the asset balances for ENSTAR and APC to determine the depreciation accrual remaining on the subledger for ENSTAR as of the end of December 31, 2007, and each subsequent calendar year, relative to the total cost remaining at the end of each year. The result is a percentage of the cost remaining belonging to ENSTAR relative to total cost. The percentage was applied to the accrued removal cost depreciation balance as of December 31, 2007, and the depreciation expense associated with removal costs for each subsequent calendar year.

As of December 31, 2017, the computed gross cumulative temporary difference related to removal costs is $20,048,107.[1] The cumulative temporary difference is not subject to the Federal income tax normalization requirements and should be separately stated as unprotected excess deferred taxes.

PwC's understanding is that ENSTAR will amortize the protected excess deferred taxes associated with depreciable method and life differences consistent with rules set forth in RSGM. ENSTAR computed a composite rate based upon the remaining useful lives, exclusive of any consideration of removal costs. The amortization of the protected excess deferred taxes is consistent with the normalization rules. Specifically, the exclusion of a depreciation factor associated with removal costs under the RSGM is appropriate.

In summary, the $74,264,715 gross temporary difference related to fixed assets should be adjusted by the $20,048,107 attributable to removal costs to reflect a gross temporary difference of $94,312,822 related to book and tax method and life depreciation differences.

We also note that $1,019,772 of gross temporary difference related to the equity allowance for funds used during construction ("equity AFUDC") was included in the $94,312,822 cumulative temporary difference above. Equity AFUDC is a regulatory method of compensating a utility for the equity financing costs it incurs during construction of new facilities. Equity AFUDC is calculated by determining a cost of equity multiplied by the construction costs and accumulated during the construction of an asset. Upon completion of construction, equity AFUDC is depreciation for book purposes.

For Federal income tax purposes, equity AFUDC is not recognized and creates a temporary difference. At December 31, 2017, the cumulative temporary difference related to equity AFUDC totaled $1,019,772.[2] Similar to removal costs, the cumulative temporary difference attributable to equity AFUDC is not subject to the Federal income tax normalization requirements and should be separately stated as unprotected excess deferred taxes. Accordingly, the $94,312,822 gross cumulative deferred tax liability attributable to method/life differences should further be adjusted to $93,293,050.[3]

APPLICATION TO APC

APC had a cumulative gross deferred tax liability at December 31, 2017 totaling $60,696,278 inclusive of a $66,143,465 gross deferred tax liability associated with "Federal Fixed Assets". The "Federal Fixed Assets" temporary difference primarily includes differences between book accounting depreciation methods and depreciable lives compared to Federal income tax depreciation methods and depreciable lives. These depreciation method and life differences are "protected" temporary differences, however, the $66,143,465 also includes cumulative temporary differences associated with removal costs which are "unprotected" by the normalization rules.

PwC was engaged to determine the amount of the gross deferred balance related to removal costs for

[1] The excess deferred tax asset totals $2,806,735 ($20,048,107 x 14%).
[2] The excess deferred tax asset totals $142,768 ($1,019,772 x 14%).
[3] The gross cumulative deferred tax liability multiplied by the 14% decrease in the Federal tax rate will be amortized under the RSGM in compliance with the normalization rules.

APC, exclusive of ENSTAR, and the related excess deferred tax resulting from the tax rate change in 2017. ENSTAR provided the depreciation study from 2007 and a subsidiary ledger schedule which identified the accumulated depreciation related to removal costs as of December 31, 2007. ENSTAR also provided a schedule detailing the book depreciation expense related to removal costs; the actual removal costs; and the actual salvage in each subsequent year.

As part of the analysis, PwC first estimated the amount of the removal costs in the depreciation accrual for removal costs which included both ENSTAR and APC operations. To calculate this amount, PwC used the asset balances for ENSTAR and APC to determine the depreciation accrual remaining on the subledger for APC as of the end of December 31, 2007, and each subsequent calendar year, relative to the total cost remaining at the end of each year. The result is a percentage of the cost remaining belonging to APC relative to total cost. The percentage was applied to the accrued removal cost depreciation balance as of December 31, 2007, and the depreciation expense associated with removal costs for each subsequent calendar year.

As of December 31, 2017, the computed gross cumulative temporary difference related to removal costs is $12,125,687.[4] The cumulative temporary difference is not subject to the Federal income tax normalization requirements and should be separately stated as unprotected excess deferred taxes.

PwC's understanding is that APC will amortize the protected excess deferred taxes associated with depreciable method and life differences consistent with rules set forth in RSGM. APC computed a composite rate based upon the remaining useful lives, exclusive of any consideration of removal costs. The amortization of the protected excess deferred taxes is consistent with the normalization rules. Specifically, the exclusion of a depreciation factor associated with removal costs under the RSGM is appropriate.

In summary, the $66,143,465 gross temporary difference related to fixed assets should be adjusted by the $12,125,687 attributable to removal costs to reflect a gross temporary difference of $78,269,152 related to book and tax method and life depreciation differences.

We also note that $2,416,326 of gross temporary difference related to the equity allowance for funds used during construction ("equity AFUDC") was included in the $78,269,152 cumulative temporary difference above. Equity AFUDC is a regulatory method of compensating a utility for the equity financing costs it incurs during construction of new facilities. Equity AFUDC is calculated by determining a cost of equity multiplied by the construction costs and accumulated during the construction of an asset. Upon completion of construction, equity AFUDC is depreciation for book purposes.

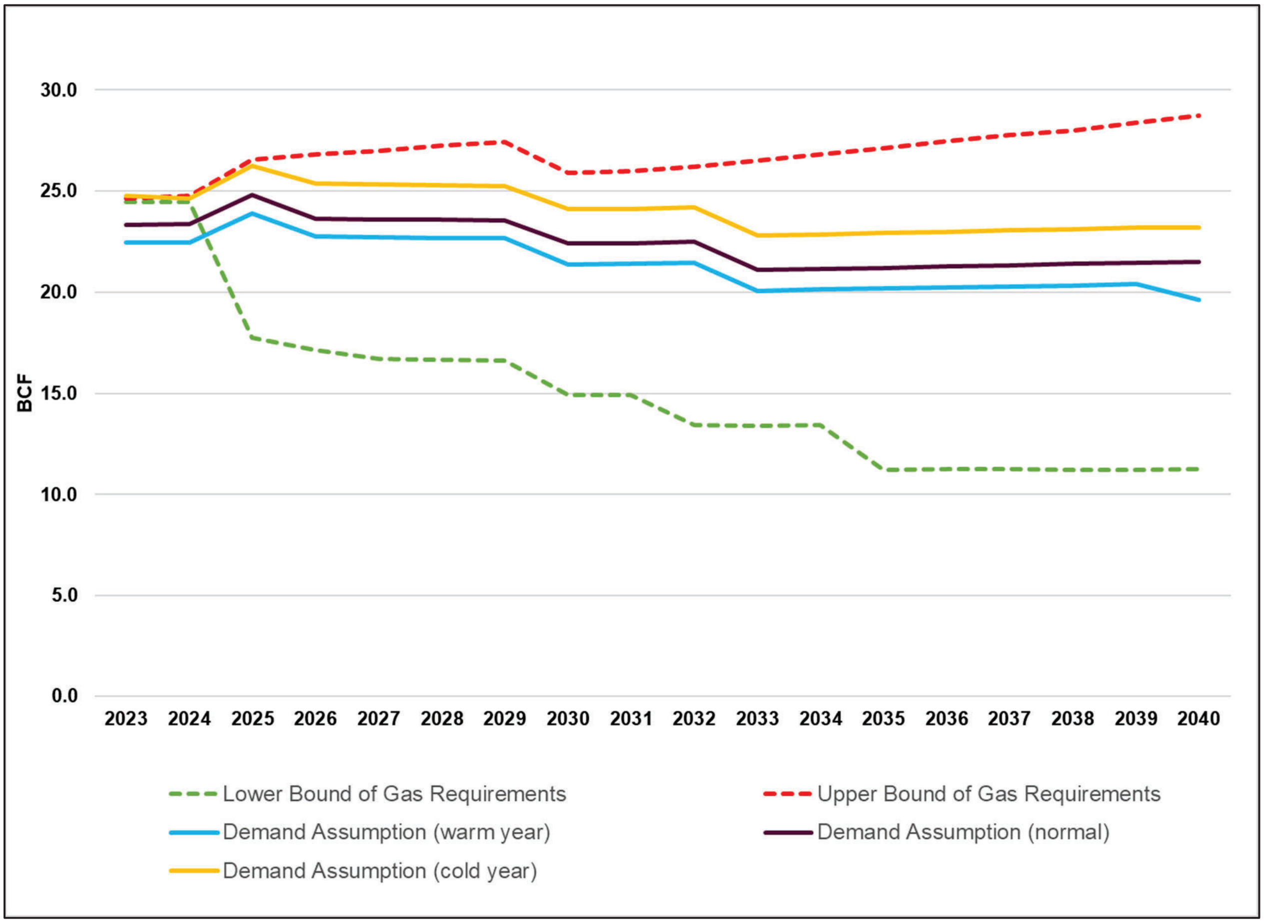
For Federal income tax purposes, equity AFUDC is not recognized and creates a temporary difference. At December 31, 2017, the cumulative temporary difference related to equity AFUDC totaled $2,416,326.[5] Similar to removal costs, the cumulative temporary difference attributable to equity AFUDC is not subject to the Federal income tax normalization requirements and should be separately stated as unprotected excess deferred taxes. Accordingly, the $78,269,152 gross cumulative deferred tax liability attributable to method/life differences should further be adjusted to $75,852,826.[6]

[4] The excess deferred tax asset totals $1,697,596 ($12,125,687 x 14%).
[5] The excess deferred tax asset totals $338,286 ($2,416,326 x 14%).
[6] The gross cumulative deferred tax liability multiplied by the 14% decrease in the Federal tax rate will be amortized under the RSGM in compliance with the normalization rules.

relatively low (0.2%) penetration of electric vehicles ("EV"), heat pumps, and induction cooking will likely grow over time and increase combined-cycle natural gas power generation demand overall. [17]

23. Figure 4 below provides a breakout of the projected electric utility[18] natural gas requirements. These requirements (represented by dotted lines) are based on planning scenarios to provide a range for strategic planning. As can be seen, there is a substantial range of projected gas requirements for the electric utilities attributed to potential varying degrees of clean energy uptake along with beneficial electrification such as EVs and heat pumps. For the purposes of project requirements, the three demand lines between the Lower and Upper Bounds of Gas Requirements were utilized since they best represent reasonable expectations and timelines.

Figure 4. Power Generation: Demand Planning Assumptions vs. Potential Bounds of Gas Requirements



[17] Alaska Energy Authority, *State of Alaska Electric Vehicle Infrastructure Implementation Plan* (approved by USDOT FHWA on September 27, 2022), pp. 25-26.

[18] CEA, MEA, HEA, and GVEA.